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 #18-3
August 22, 2018 10:00 a.m. – 4:00 p.m. EST
August 23, 2018 8:30 a.m. – 12:00 p.m. EST
Hydro Quebec Office: Maison du développement durable
Meeting Room: Conseil
50 Sainte-Catherine Street West
Montreal, QC Canada H2X 3V4
Attire: Business Casual

Dial-In: 1-855-327-2733

Pin: 8675894

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated January 31, 2018
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 NARUC 2018 Summer Policy Summit
5.3 FERC Final Rule E-1 Cyber Security Incident Reporting Reliability Standards, Docket No. RM18-2-000 FERC Order #848
5.4 Informational Filing re BAL-003-1.1 Frequency Response and Frequency Bias Setting

5.5 Comments of NERC in Response to Notice of Proposed Rulemaking

5.6 NPCC Goals – Approach and Process Development for DER Distribution Level Reliability Impacts

5.7 Standards Efficiency Review

5.8 CAL-ISO SARs on DER

5.9 Canadian-specific Revisions to TPL-007-2 Presentation by Hydro One

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
Project 2015-10 Single Points of Failure TPL-001	9/14/18 (F)	9/14/18 (A)
Project 2017-01 Modifications to BAL-003-1.1		
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)
Project 2016-02 Modifications to CIP Standards	7/13/18 (I)	8/13/18 (F)
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)	
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards	2/23/18 (F)	
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-01 Canadian-specific Revisions to TPL-007-2	4/30/18 (F)	
Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	9/10/18 (I)	
Revisions to the NERC Standard Processes Manual	8/9/18 (A)	5/3/17 (I)
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 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding status update

9.0 NPCC Non-Standards
https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Directories:

9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS
RAS Implementation/Transition

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

9.1.3 NPCC BOD Directive --- Strategic Review of the Need for NPCC Criteria

9.1.4 Directory#5 *Reserve* - (status of TFCO review).

9.1.5 Directory#8 System Restoration ---- Additional TFCO Revisions

9.1.6 Directory Manual --- Periodic Review and Incorporate A-01
Open Process Comment Review and RSC Approval of Revised Manual

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 17th – Call	February 14th – Call	March 14th – Meeting
April 18th – Call	May 16th – Call	June 13th – Meeting
July 18th – Call	August 22th – Call	September 13th Meeting
October 17th – Call	November 14th – Call	December 12th – 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

January 4th - Call	February 22nd - Call	March 13th – Meeting
March 29th – Call	May 24th - Call	June 12th – Meeting
June 28th – Call	August 23rd – Call	September 11th – Meeting
September 27th – Call	November 15th – Call	December 4th - Meeting

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

March 14th - Meeting	June 13th - Meeting	September 12th Meeting
December 5th - Meeting		

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

February 7-8 - Meeting	May 9-10 - Meeting	August 15-16 - Meeting
November 6-7 - Meeting		

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 four new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2018

January 31st – NERC Office, Washington, DC	March 21st - Call	May 2nd – NPCC Office
June 6th – Call	June 27th – NPCC Office	August 8th – Call
September 5th and 6th – Saratoga Springs NY	October 31st – Call	December 5th – Toronto ON

14.2 ISO-NE Fuel Security Study

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

March 7th-8th, Entergy, Woodlands Texas
June 20th-21th, Saratoga NY
August 22th-23th, Montreal Canada
October 10th-11th, Lewiston NY
December 6th, Toronto Ontario

15.2 RSC 2018 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 19	February 2	February 16
March 23	April 6	April 20
May 4	May 18	June 22
July 13	July 27	August 10
September 14	September 28	October 26
November 9	November 23	December 21

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, Inc.

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #18-2
June 20, 2018 10:00 a.m. – 4:00 p.m. EST
June 21, 2018 8:30 a.m. – 12:00 p.m. EST
NYISO Hosting at Hampton Inn & Suites
25 Lake Ave
Saratoga Springs, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)

Day 1:
Guest Code: 317142626
Password: pJnPt4?8 (75678408 from phones)

Day 2:
Guest Code: 310962896
Password: 9QxM99R@ (97969971 from phones)

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated January 31, 2018
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	Via Phone
3.	Ruida Shu	Northeast Power Coordinating Council		1, 2	
4.	Chantal Mazza	Hydro Quebec	2	1, 2	
5.	Mike Jones	National Grid	3	1, 2	
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	
7	Quintin Lee	Eversource Energy	1	1, 2	
8.	Joel Charlebois	AESI, Inc.	Guest	1, 2	
9.	Chris Overberg	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1, 2	
10.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	
11.	David Lemstra	Ontario Power Generation, Inc.	Guest	1, 2	
12.	Glen Smith	Entergy Services, Inc.	4	1, 2	

13.	Laura Mcleod	New Brunswick Power Corporation	1	1, 2	Via Phone
14.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	
15.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1	
16.	Brian Robinson	Utility Services, Inc.	5	1, 2	
17.	Sean Bodkin	Dominion Resources Services	4	1, 2	Via Phone
18.	Helen Lainis	IESO	2	1	Via Phone
19.	Scott Berry	IESO	2	1, 2	
20.	Sean Lagan	IESO	Guest	1, 2	
21.	Salvatore Spagnolo	NYPA	4	1, 2	
22.	Shivaz Chopra	NYPA	4	1	
23.	Michele Tondalo	The United Illuminating Company	1	1, 2	
24.	Jim Grant	NYISO	2	1, 2	
25.	Greg Campoli	NYISO	2	1	
26.	Mark Capano	NYISO	Guest	1	
27.	Josh Eason	ISO-NE	2	1	
28.	David Kiguel	Independent	7	1	Via Phone
29.	Vijay Puran	New York State Department of Public Service	6	1	2nd Day Via Phone
30.	Sean Cavote	PSEG	4	1, 2	Via Phone
31.	Edwin Thompson	Consolidated Edison Co. of New York, Inc.	Guest	1	Via Phone

Introductions and Chair's Remarks
Guy Zito welcomed everyone to Saratoga Springs NY.

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

Agenda Items:

1.0 Review of Agenda
Guy Zito made a few changes to the order of the agenda so Edwin Thompson can call in at 10:30AM for his UFLS presentations.

2.0 RSC Meeting Minutes

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 3-7-18

Herb Schrayshuen made the motion for approval.
Scott Berry seconded the motion.
The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

The RSC members reviewed the roster, put several projects into the inactive section and added several NPCC members to the roster.

3.2 Executive Tracking Summary

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

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

Action Item #1--Mike Jones, Quintin Lee and Herb Schrayshuen volunteered to assist Guy Zito and Ruida Shu on reviewing the NPCC RSPM by the end of the year.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin

Guy Zito reviewed the NERC weekly standards bulletin with the RSC group.

5.2 Standards Efficiency Review

Guy Zito provided a summary on the Standards Efficiency review, Greg Campoli and Scott Berry both are participating on the SER drafting team and they reviewed the SER spreadsheet with the group.

5.3 FERC Order No.743 Final Rule for Approving CIP-003-7

Herb Schrayshuen provided some background on the FERC order.

5.4 Project 2018-1 Canadian-specific Revisions to TPL-007-2

Payam Farahbakhsh provided an update on the Project 2018-1.

The SC met on June 13, 2018 and approved the drafting team members.

The drafting team is planning to meet in July 2018 in person to start the Project.

The goal is to keep the reliability objective however the approach will be different.

5.5 Project 2015-10 Single Points of Failure TPL-001

Project 2015-10 needs to address two FERC Orders #754 and #786.

There is a drafting team meeting for Project 2015-10 next week.

5.6 NPCC Goals – Approach and Process Development for DER Distribution Level Reliability Impacts

Guy Zito reviewed the DER proposal VISIO file with the RSC group.

The RSC added a few extra steps to the process and Ruida Shu updated the VISIO file.

5.7 FERC Resilience Proceeding Comments

Various technical committees have submitted comments in regards to Resilience.

The goal is to add Resilience into the Periodic review template and standard grading template.

On March 14, 2019 there is an event in DC on Reliability Leadership Summit.

It is a NERC lead event which occurs once every two years.

5.8 Con Edison Presentations on PRC-006-NPCC-2

Edwin Thompson called in at 10:30AM and provided two presentations to the RSC group on PRC-006-NPCC-1 UFLS.

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
Project 2015-10 Single Points of Failure TPL-001	4/23/18 (F)	4/23/18 (A)	Latrice Harkness
Project 2017-01 Modifications to BAL-003-1.1	12/1/17 (F)		Laura Anderson
Project 2017-06 Modifications to BAL-002-2	5/8/18 (F)	5/8/18 (I)	Darrel Richardson
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)	Darrel Richardson
Project 2017-05 NUC-001-3 Periodic Review	1/29/18 (F)		Mat Bunch
Project 2016-02 Modifications to CIP Standards CIP-012-1	7/2/18 (F)	7/2/18 (A)	Jordan Mallory Mat Bunch
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)		Al McMeekin
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards	2/23/18 (F)		Laura Anderson
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)		Laura Anderson
Project 2018-01 Canadian-specific Revisions to TPL-007-2	4/30/18 (F)		Mat Bunch
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final			

Guy Zito reviewed the status for Project 2015-10, 2017-01, 2017-6, 2015-09, 2017-05, 2017-03, 2017-04, 2017-07 and 2018-01.
Ruida Shu provided a status update for Project 2016-02.

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.

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 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding status update

Ruida Shu provided a summary on the status for the PRC-006-NPCC-2.

The drafting team meet last week on June 13-15, 2018, the drafting team provided a response to all comments and there are still two concerns needs to be solve. Requirement 5 and 18 are still pending. The goal is to put this out for a third comment period mid-end of July 2018.

Action Item: Mike Jones volunteered to help with the UFLS Standard quality review.

Ruida Shu and Guy Zito will contact NERC for some technical writer help on the quality review of the UFLS Regional Standard.

The RSC approved the drafting team to post for a 3rd comment period with unanimous decision.

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS

RAS Implementation/Transition

TFCP currently reviewing Directory#7 Appendix B in order to align the NPCC SPS review process with PRC-012-2.

TFCP and TFSS coordinating implementation of the RAS definition with NPCC.

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

TFCP Working Group CP-11 currently reviewing the A-10 methodology. In accordance with RCC direction, CP-11 currently testing three proposals to identify critical facilities within NPCC.CP-11 anticipates presenting the 1st iteration of test results to the TFCP in mid -August. Subsequent to Task

Force review final recommendation on a preferred methodology will be presented to the RCC in December.

CP-11 anticipates revising the A-10 document and posting proposed revisions to the Open Process during 2019.

9.1.3 NPCC BOD Directive --- Strategic Review of the Need for NPCC Criteria

In accordance with an approved Action Plan, a first draft of the Strategic Review has been distributed to the TFCP, TFCO, TFSS and TFSP for comment.

Subsequent to TF comment an initial draft of the Strategic Review will be presented to the RCC and RSC for a 30-day comment period.

In accordance with a BOD approved corporate goal a final version of the Strategic Review will be presented to the RCC in December.

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

A revised version of Directory#2 is currently being balloted by the NPCC Full Member Committee.

TFCO and its CO-8 Working Group reformatted the Directory#2 criteria into NERC style requirements and reviewed the more stringent criteria to eliminate any duplicity with the relevant NERC standards.

Update: Directory#2 approved by the Full Member Committee on June 29, 2018.

9.1.5 Directory#8 System Restoration ---- TFSP revisions

TFSP and TFCO proposed revisions to R10 currently posted for comment until 7/15.

D#8 R10 revised to align testing requirements for critical components with PRC-005.

9.1.6 Directory Manual --- Periodic Review and Incorporate A-01

RSC and TFCP proposed revisions to the NPCC Directory Manual to incorporate relevant portions of NPCC document A-01 into the Manual in advance of retiring the A-01.

The revised Manual was posted to the Open Process through early June 2018. RSC will consider comments and a final draft of the Directory Manual is anticipated to be presented to the RSC for approval in in August 2018.

TFCP will consider a recommendation to retire the A-01in August 2018.

9.1.7 Directory#1 Design and Operation of the BPS ---- Status of NYSRC Clarification Request.

RCC approved the final clarification on May 30, 2018.

10.0 RSC Member Items of Interest

10.1 RSC Roster

Ruida Shu updated the RSC roster per the members of RSC.

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 17th – Call	February 14th – Call	March 14th – Meeting
April 18th – Call	May 16th – Call	June 13th – Meeting
July 18th – Call	August 22th – Call	September 13th Meeting
October 17th – Call	November 14th – Call	December 12th – 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

January 4th - Call	February 22nd - Call	March 13th – Meeting
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12.3 Standards Committee Project Management and Oversight Subcommittee (PMOS)
http://www.nerc.com/comm/SC/Pages/ProjectManagementandOversightSubcommittee(PMOS).aspx

March 14th - Meeting	June 13th - Meeting	September 12th Meeting
December 5th - Meeting		

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

12.5 Board of Trustees (BOT) Meeting
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February 7-8 - Meeting	May 9-10 - Meeting	August 15-16 - Meeting
November 6-7 - Meeting		

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 three new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2018

January 31st – NERC Office, Washington, DC	March 21st - Call	May 2nd – NPCC Office
June 6th – Call	June 27th – NPCC Office	August 8th – Call
September 5th and 6th – Saratoga Springs NY	October 31st – Call	December 5th – Toronto ON

14.2 CAMPUT (Canadian Association of Members of Public Utility Tribunals)
14.3 FERC Technical Conference
14.4 NPCC Draft 2019 Business Plan and Budget

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

March 7th-8th, Entergy, Woodlands Texas
June 20th-21th, Saratoga NY
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15.2 RSC 2018 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 19	February 2	February 16
March 23	April 6	April 20
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July 13	July 27	August 10

September 14	September 28	October 26
November 9	November 23	December 21

The meeting is adjourned at 10:09AM on June 21, 2018.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

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- The resale prices their customers should charge for products they sell them;
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NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
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				
2016-02	Modification to CIP Standards	Standard	Steve Brain Abdo Saad	Dominion Resource Services, Inc. Con Edison		
2016-04	Modifications to PRC-025-1	Standard	Juan Alvarez	Utility Services		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard	Jessica Tang	IESO		
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards - PER-003, PER-004	Standard				
2017-06	Modifications to BAL-002-2	Standard				
2017-07	Standards Alignment with Registration	Standard	Mark Atkins	AESI		
2018-01	Canadian-specific Revisions to TPL-007-2	Standard	Majid Fassi Fehri Loui Gibson Steve Burns Cynthia Yiu Phillip Hiusser	Hydro Quebec Hydro Quebec IESO Hydro One OPG		
Source = NERC Standard Drafting Team Rosters - July 2017						

NPCC Directory Executive Tracking Summary

Revised: **7/24/2018** 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

NPCC Directory Executive Tracking Summary

Revised: 7/24/2018

	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	D#2 Criteria Reformatted into NERC Style Requirements.	Pending RCC and Full Member Ballot Approval.
	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.
	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		Currently Under TFSP Review.
	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		TFCO Working Group CO-1 Currently Reviewing Reformatted Draft of Directory#5.
	Directory #6		Regional Reserve Sharing		Apr-12		
	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13	TFSP Reviewing D#7 Criteria; TFCP Coordinating Review of D#7 Attachment B.	Currently Under TFCP and TFSP Review.
	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-17	TFCO/TFSP Revisions.	TFCO considering further revisions.
	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		NPCC Full Members approved retirement of D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019).
	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
	A-10 Criteria	N/A	Classification of BPS Elements	TFCP	Dec-09	RCC Approved CP-11 Proposed Methodolgies for Testing in Phase 2.	Testing of Proposed Methodologies Underway.
	A-01 Criteria	N/A	Criteria for Review and Approval of Documents	TFCP	Oct-17	Proposed for Retirement	Pending TFCP and RCC approval
	C-46 Procedure	N/A	Procedure for Operations Planning Model Data Exchange	TFCO	New	TFCO Proposing New Document	Pending TFCO Approval

NPCC Directory Criteria Clarifications

Revised: 7/24/2018 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
9	Directory#1 Clarification	Design and Operation of the BPS	9/7/2016	TFCP	Yes	Yes	Clarification on Behalf of New Brunswick	Complete
10	Directory#4 Clarification	System Protection Criteria	12/2/2016	TFSP	Yes	Yes	Clarification on Behalf of Eversource	Complete
11	Directory #4 Clarification	System Protection Criteria	12/5/2017	TFSP	Yes	Yes	Clarification on Behalf of Eversource.	Complete
12	Directory#1 Clarification	Design and Operation of the BPS	5/30/2018	TFCP/TFCO	Yes	Yes	Clarification on Behalf of NYSRC	Complete

7/24/2018

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.
July 1 to September 30, 2015	12/1/2015	11/25/2015	Revisions to D#1 and D#4 approved by the Full Members on 9/30/2015.
October 1 to December 31, 2015	3/1/2016	N/A	No changes were made during the referenced period which required filing.
January 1st to March 31st, 2016	6/1/2016	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2016	9/1/2016	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2016	12/1/2016	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2016	3/1/2017	2/28/2017	Directory#11 approved by Full Members October 2016.
January 1st to March 31st 2017	6/1/2017	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th, 2017	9/1/2017	Will Not Be Filed.	Revisions to the A-01 Document approved by the Full Members on 4/21/2017.
July 1 to September 30, 2017	12/1/2017	2/28/2018	On August 3, 2017 NPCC Full Members approved retirement of Directories #9 and #10 effective July 1, 2019
October 1 to December 31, 2017	3/1/2018	2/28/2018	Revisions to D#8 approved by the Full Members on 10/06/2017.
January 1st to March 31st, 2018	6/1/2018	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th, 2018	9/1/2018	Pending	Revisions to Directory #2 approved by the Full Members on 6/29/2018.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SUMMARY | Updated: 8/21/2018 | Nom-SAR/D | QR | Posting-SAR or PR | Posting-Commen

Tutorial Video (11 min)

Click here to report errors or issues

HOME | DO NOT SORT (Filtering Ok) | Early/(Late) | Baseline/ Current | 2018 | Jul | Aug | Sep | Oct | Nov | Dec

U	Project (Filter)	Deliverables (Filter)	Days (Filter)	(Filter)
G	2015-09 - Establish and Communicate System Op	CIP-014-3, FAC-003-5, FAC-013	(219)	Current
G	2015-09 - Establish and Communicate System Op	IROL Stds.		N/A
G	2015-10 - Single Points of Failure TPL-001	TPL-001-5	(280)	Current
G	2016-02 - Modifications to CIP Standards	Directives, Control Center Com	(289)	Current
G	2016-02 - Modifications to CIP Standards	Address TO Control Centers Pe	(465)	Current
G	2016-02 - Modifications to CIP Standards	Address all remaining V5TAG is	No schedule	N/A
G	2016-02 - Modifications to CIP Standards	FERC Order No. 843 Malicious	No schedule	N/A
G	2017-01 - Modifications to BAL-003-1.1	BAL-003-2		Proposed
G	2017-02 - Modifications to Personnel Performan	PER-003-2, retire PER-004-2	24	Proposed
G	2017-03 - Periodic Review of FAC-008-3 Standarc	Periodic Review Recommenda		N/A
G	2017-04 - Periodic Review of Interchange Schedu	Periodic Review Recommenda		N/A
G	2017-05 - Project 2017-05 NUC-001-3 Periodic R	Periodic Review of NUC-001-3		N/A
G	2017-06 - Project 2017-06 Modifications to BAL-	BAL-002-3		Proposed
G	2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE		Proposed
G	2018-01 - Canadian-specific Revisions to TPL-007	TPL-007-3		Proposed

Project	Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable Footnote	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
SUMMARY	(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
2015-09	Establish and Communicate System Operating Limits	On Hold	The IROL portion of the project has been placed on hold pending additional information.	IROL Stds.	N/A	Medium	N/A	N/A	N/A	N/A	Al McMeekin	TBD - On Hold	TBD - On Hold	8/20/2018
2015-09	Establish and Communicate System Operating Limits	Pending SC Action	Anticipate posting on August 24, 2018. An SDT meeting is planned for October 23-24 in conjunction with the CIP SDT.	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, and PRC-026-2	N/A	Footnote 7, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Ken Lanehome	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, and PRC-026-2	8/20/2018
2015-10	Single Points of Failure TPL-001	Posted	The project is posted for a 45-day formal comment period through 8 p.m. Eastern, Tuesday, September 11, 2018. The Implementation Plan has been updated to reflect a revised compliance date. The comment period has been extended to provide stakeholders adequate time to review the updated documents and provide meaningful feedback.	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	8/20/2018
2016-02	Modifications to CIP Standards	SDT Development	The SDT conducting outreach and will hold posting of the standards until January of 2019 to allow CIP-008 to complete the current FERC directive.	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-005, CIP-007 and CIP-010	8/21/2018
2016-02	Modifications to CIP Standards	Pending Regulatory Filing	CIP-012-1 was approved by industry and the NERC Board adopted the standard at its August 2018 meeting.	Directives, Control Center Comm Nets (CIP-012-1)/ Control Center definition	N/A	Footnote 8, High	N/A	2	N/A	N/A	Jordan Mallory	Ken Lanehome and Ash Mayfield	CIP-012-1	8/21/2018
2016-02	Modifications to CIP Standards	Pending SC Action	The SDT is seeking SC authorization to post for initial comment and ballot at the August 22, 2018 conference call. Posting anticipated immediately after August 23, 2018.	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome and Ash Mayfield	CIP-002-5.1a	8/21/2018
2016-02	Modifications to CIP Standards	Working to Initial Ballot	The team will be seeking authroization to post for initial comment and ballot period at the August 22, 2018 SC meeting. If approved, the standard will be posted shortly thereafter.	FERC Order No. 843 Malicious Code Example Directive	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-003-7	8/21/2018
2017-01	Modifications to BAL-003-1.1	Working to Comment Posting	Meetings are scheduled for the week of August 27, 2018 at NWPP Office in Portland, OR and the week of Sepetember 24, 2018 at SPP in Little Rock, AR	BAL-003-2	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	8/20/2018
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards	Pending Regulatory Approval	NERC filed a petition for approval of PER-003 on July 23, 2018.	PER-003-2, retire PER-004-2	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski	PER-003-1 & PER-004-2	8/20/2018
2017-03	Periodic Review of FAC-008-3 Standard	On Hold	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS item until the Standards Efficiency Reviews are complete.	Periodic Review Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Al McMeekin	Mark Pratt	FAC-008-3	8/20/2018
2017-04	Periodic Review of Interchange Scheduling and Coordination Standards	On Hold	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	Periodic Review Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	8/20/2018
2017-05	Project 2017-05 NUC-001-3 Periodic Review	On Hold	The review template 45-day posting for preliminary recommendations ended January 29, 2018. There is a meeting scheduled for March 19 to review industry comments and discuss the team's final recommendation. Given the overwhelming industry support for the team's Preliminary Recommendation (Yellow-Revise), they do not anticipate a change in the recommended "color" of the standard. The PRT recommends to reaffirm the standard and has placed the project on hold pending the Standards Efficiency Reivew outcomes.	Periodic Review of NUC-001-3 Standard	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Mat Bunch	Amy Casuscelli and Colby Bellville	NUC-001-3	8/20/2018
2017-06	Project 2017-06 Modifications to BAL-002-2	Working to Final Ballo	The final ballot posting ended July 16, 2018. The standard has passed with about 84% approval. NERC filed a petition for approval on August 17, 2018.	BAL-002-3	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Ken Lanehome	BAL-002-2	8/20/2018

2017-07	Stds Alignment with Registration	Working to Comment Posting	Project 2017-07 Standards with Alignment, at the last Standards Committee (SC) meeting, appointed the standards drafting team. The standards development project had its kick-off meeting August 1-2, 2018. A Webinar is planned for August 14, 2018. Anticipate presenting the documents to the SC on August 23, 2018 with a request for authorization to post initially.	Standards with PSE, IA, or LSE		N/A					Laura Anderson	Mike Brytowski		8/20/2018
2018-01	Canadian-specific Revisions to TPL-007-2	Posted	The SDT met July 31- August 1, 2018 in Montreal, Quebec to craft changes to the TPL-007-2 standard. The standard is posted through September 6, 2018.	TPL-007-3	N/A	N/A	N/A	N/A	N/A	N/A	Mat Bunch	Charles Yeung	TPL-007-2	8/20/2018
2018-02	Modifications to CIP-008 Cyber Security Incident Reporting	Nominations & SAR	A nomination period for Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting standard drafting team members is open through 8 p.m. Eastern, Wednesday, August 29, 2018. An informal comment period for the Standard Authorization Request is open through 8 p.m. Eastern, Monday, September 10, 2018.	CIP-008-6	1/19/2019	High	N/A	Order No. 848 (1 Directive, 4 elements)	N/A	N/A	Alison Oswald	TBD	CIP-008-5	8/21/2018

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Pending SC Action
Comments	Anticipate posting on August 24, 2018. An SDT meeting is planned for October 23-24 in conjunction with the CIP SDT.
Deliverable	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, and PRC-026-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 7, 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	Ken Lanehome
Affected Standards	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, and PRC-026-2
Last Updated	8/20/2018

Home

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 / PR							
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	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	4/9/2018	5/24/2018	1/17/2018	3/2/2018	(82)		
CAB - Com/Add Ballot 3	8/24/2018	10/8/2018					not in original baseline
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/7/2018	11/17/2018	4/2/2018	4/12/2018	(219)		
PTB - Present to BOT	11/15/2018	11/17/2018	5/1/2018	5/3/2018	(198)		
Filing - Filing with Regulators	12/15/2018	12/18/2018	6/1/2018	6/4/2018	(197)		
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.
Developer change	4/1/2017	Added Al McMeekin to the project.

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	On Hold	
Comments	The IROL portion of the project has been placed on hold pending additional information.	
Deliverable	IROL Stds.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	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	Al McMeekin	
PMOS Liaison	TBD - On Hold	
Affected Standards	TBD - On Hold	
Last Updated	8/20/2018	

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 / PR							
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
Bifurcate Project	3/31/2017	Split the IRO portion into this section for tracking.
Worksheet created	8/10/2017	PMOS suggested visibility on this IROL portion.
Worksheet made visible	4/25/2018	PMOS requested that the IRO portion be tracked going forward.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Posted
Comments	The project is posted for a 45-day formal comment period through 8 p.m. Eastern, Tuesday, September 11, 2018. The Implementation Plan has been updated to reflect a revised compliance date. The comment period has been extended to provide stakeholders adequate time to review the updated documents and provide meaningful feedback.
Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	8/20/2018

Home

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 / PR	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	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/8/2017	10/23/2017	7/5/2017	8/18/2017	(65)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	2/23/2018	4/23/2018	10/18/2017	12/1/2017	(128)		Period extended from 4/9 to 4/23 due to changes
CAB - Com/Add Ballot 3	***7/30/2018***	***9/14/2018***					Additional period
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/15/2018	10/24/2018	1/8/2018	1/17/2018	(280)		
PTB - Present to BOT	11/6/2018	11/8/2018	2/1/2018	2/3/2018	(278)		
Filing - Filing with Regulators	12/6/2018	12/9/2018	3/1/2018	3/4/2018	(280)		
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.
Accept Schedule	4/27/2017	Accepted by PMOS.

Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Pending Regulatory Filing
Comments	CIP-012-1 was approved by industry and the NERC Board adopted the standard at its August 2018 meeting.
Deliverable	Directives, Control Center Comm Nets (CIP-012-1)/ Control Center definition
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Jordan Mallory
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	CIP-012-1
Last Updated	8/21/2018

Home

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 / PR							
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	2/10/2017	3/13/2017					
CP2 - Comment Period 2	8/14/2017	9/12/2017	12/2/2016	1/16/2017	(255)		Informal for definition
CIB - Com/Ballot 1 (Initial)	7/27/2017	9/11/2017	3/31/2017	5/15/2017	(118)		

CAB - Com/Add Ballot 2	10/27/2017	12/11/2017	8/15/2017	9/29/2017	(73)		Does not include the informal 21 day comment on Implementation Guidance ending on 12/11/2017
CAB - Com/Add Ballot 3	3/16/2018	4/30/2018					
CAB - Com/Add Ballot 4	5/18/2018	7/2/2018					
CAB - Com/Add Ballot 5							
FB - Final Ballot	8/2/2018	8/9/2018	10/17/2017	10/27/2017	(289)		
PTB - Present to BOT	11/6/2018	11/8/2018	11/7/2017	11/9/2017	(364)		
Filing - Filing with Regulators	12/1/2018	12/4/2018	12/28/2017	12/31/2017	(338)		
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.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Change in Approach	6/27/2017	Team decided to create CIP-012-1 and not modiifying CIP-006 for Communcation Networks.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
Developer Change	6/13/2018	Mat Bunch was removed from the project.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Pending SC Action
Comments	The SDT is seeking SC authorization to post for initial comment and ballot at the August 22, 2018 conference call. Posting anticipated immediately after August 23, 2018.

Home

Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Jordan Mallory
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	CIP-002-5.1a
Last Updated	8/21/2018

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 / PR							
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	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2	6/14/2018	7/13/2018					IROL for CIP-002
CIB - Com/Ballot 1 (Initial)	9/14/2017	10/30/2017	12/2/2016	1/15/2017	(286)		See notes for 8/10 and 8/25.
CAB - Com/Add Ballot 2	12/5/2017	1/18/2018	3/31/2017	5/14/2017	(249)		
CAB - Com/Add Ballot 3	8/23/2018	4/30/2018	8/15/2017	9/28/2017	(373)		Going back to initial ballot
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/15/2018	10/17/2017	10/27/2017	(465)		
PTB - Present to BOT	2/6/2019	2/8/2019	11/7/2017	11/9/2017	(456)		
Filing - Filing with Regulators	4/1/2019	4/4/2019	12/28/2017	12/31/2017	(459)		
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.

Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Schedule Adjustment	8/10/2017	The original 5/15/2017 planned posting was accepted for 9/18 to stagger 2013-03, 2015-09,
Schedule Adjustment	8/25/2017	The posting was advanced due to 2015-09 (SOL) being moved from its 9/12 posting to 9/30.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
SC Action	6/13/2018	The SC accepted the SAR to address recommended revisions to CIP-002 provided by Project
Developer Change	6/13/2018	Mat Bunch was removed from the project.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	SDT Development	
Comments	The SDT conducting outreach and will hold posting of the standards until January of 2019 to allow CIP-008 to complete the current FERC directive.	
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP-005, CIP-007 and CIP-010	
Last Updated	8/21/2018	

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 / PR							
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	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2	10/6/2017	11/2/2017					Unplanned

CIB - Com/Ballot 1 (Initial)	9/13/2018	10/27/2018	9/13/2018	10/29/2018			
CAB - Com/Add Ballot 2	12/14/2018	1/28/2019	12/14/2018	1/28/2019			
CAB - Com/Add Ballot 3	3/5/2019	4/19/2019	3/2/2019	4/19/2019	(3)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/13/2019	5/23/2019	5/13/2019	5/23/2019			
PTB - Present to BOT	8/6/2019	8/8/2019					
Filing - Filing with Regulators	9/1/2019	9/4/2019					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	8/8/2017	This fourth segment of the project was made to address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.
Assign PMOS Liaison	10/12/2017	Assigned Kirk Rosener to support Ken Lanehome and Ash Mayfield.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
Developer Change	6/13/2018	Mat Bunch was removed from the project.
Accept baseline schedule		Following appointment of additional members

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Working to Initial Ballot	
Comments	The team will be seeking authroization to post for initial comment and ballot period at the August 22, 2018 SC meeting. If approved, the standard will be posted shortly thereafter.	
Deliverable	FERC Order No. 843 Malicious Code Example Directive	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP-003-7	
Last Updated	8/21/2018	

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 / PR							
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)	8/22/2018		8/22/2018	10/1/2018			
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot			10/29/2018	11/8/2018			
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	7/30/2018	CIP-003 for malicous code was segmented into its own tracking worksheet.

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1.1	
Status	Working to Comment Posting	
Comments	Meetings are scheduled for the week of August 27, 2018 at NWPP Office in Portland, OR and the week of Sepetember 24, 2018 at SPP in Little Rock, AR	

Deliverable	BAL-003-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Laura Anderson
PMOS Liaison	Amy Casuscelli & Linda Lynch
Affected Standards	BAL-003-1.1
Last Updated	8/20/2018

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 / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							

SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	11/6/2018	1/9/2019	11/6/2018	1/9/2019			
CAB - Com/Add Ballot 2	2/18/2019	4/3/2019	2/18/2019	4/3/2019			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/16/2019	4/25/2019	4/16/2019	4/25/2019			
PTB - Present to BOT	5/9/2019	5/11/2019	5/9/2019	5/11/2019			
Filing - Filing with Regulators	6/9/2019	6/16/2019	6/9/2019	6/16/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Add Linda Lynch to support Amy Casuscelli.
Updated Standard Number	6/6/2018	Changed standard from BAL-003-1 to BAL-003-1.1.
Accept baseline	7/18/2018	PMOS accepted baseline project schedule.

Project	**2017-02**	**Home**
Project Name	Modifications to Personnel Performance, Training, and Qualifications Standards	
Status	Pending Regulatory Approval	
Comments	NERC filed a petition for approval of PER-003 on July 23, 2018.	
Deliverable	PER-003-2, retire PER-004-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Mike Brytowski	
Affected Standards	PER-003-1 & PER-004-2	
Last Updated	8/20/2018	

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 / PR							EPR SDT appointed as SDT
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/21/2017	7/24/2017	6/21/2017	7/24/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	1/22/2018	3/7/2018	1/22/2018	3/7/2018			97.50%
CAB - Com/Add Ballot 2							

CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/3/2018	4/12/2018	4/27/2018	5/6/2018	24		
PTB - Present to BOT	5/9/2018	5/11/2018	5/9/2018	5/11/2018			
Filing - Filing with Regulators	6/9/2018	6/11/2018	6/9/2018	6/11/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Mike Brytowski accepted appointment as PMOS liaison.
Accept Baseline	1/31/2018	PMOS accepted baseline.
Archive Project	9/13/2018	PMOS archived project as it was filed on July 23, 2018

Project	**2017-03**	**Home**
Project Name	Periodic Review of FAC-008-3 Standard	
Status	On Hold	
Comments	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS item until the Standards Efficiency Reviews are complete.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
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	Mark Pratt	
Affected Standards	FAC-008-3	
Last Updated	8/20/2018	

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 / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	10/30/2017	12/13/2017	10/30/2017	12/13/2017			
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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Mark Pratt accepted appointment as PMOS liaison.

Project	**2017-04**	**Home**
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards	
Status	On Hold	
Comments	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
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	Laura Anderson	
PMOS Liaison	Charles Yeung	
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	8/20/2018	

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 / PR	5/2/2017	5/15/2017	5/2/2017	5/15/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							

CP1 - Comment Period 1	1/10/2018	2/23/2018					
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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Charles Yeung accepted appointment as PMOS liaison.

Project	**2017-05**	**Home**
Project Name	Project 2017-05 NUC-001-3 Periodic Review	
Status	On Hold	
Comments	The review template 45-day posting for preliminary recommendations ended January 29, 2018. There is a meeting scheduled for March 19 to review industry comments and discuss the team's final recommendation. Given the overwhelming industry support for the team's Preliminary Recommendation (Yellow-Revise), they do not anticipate a change in the recommended "color" of the standard. The PRT recommends to reaffirm the standard and has placed the project on hold pending the Standards Efficiency Reivew outcomes.	
Deliverable	Periodic Review of NUC-001-3 Standard	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
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	Mat Bunch	
PMOS Liaison	Amy Casuscelli and Colby Bellville	
Affected Standards	NUC-001-3	
Last Updated	8/20/2018	

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 / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	12/15/2017	1/29/2018	12/4/2017	1/17/2018	(11)		
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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Assigned Colby Bellville to support Amy Casuscelli (new SC vice chair)

Project	**2017-06**	**Home**
Project Name	Project 2017-06 Modifications to BAL-002-2	
Status	Working to Final Ballot	
Comments	The final ballot posting ended July 16, 2018. The standard has passed with about 84% approval. NERC filed a petition for approval on August 17, 2018.	

Deliverable	BAL-002-3
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Ken Lanehome
Affected Standards	BAL-002-2
Last Updated	8/20/2018

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 / PR	6/20/2017	7/3/2017	6/20/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/20/2017	7/20/2017	6/20/2017	7/20/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	3/22/2018	5/8/2018					

CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	6/29/2018	7/8/2018					
PTB - Present to BOT	8/15/2018	8/17/2018					
Filing - Filing with Regulators	8/17/2018	8/20/2018					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/30/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Ken Lanehome accepted appointment as PMOS liaison.
SAR	2/14/2018	SC accepts the final SAR.
Accept Baseline	N/A	Project schedule baseline was never submitted to PMOS.
Archive Project	9/13/2018	PMOS archived project as it was filed on August 17, 2018.

Project	**2017-07**	**Home**
Project Name	Stds Alignment with Registration	
Status	Working to Comment Posting	
Comments	Project 2017-07 Standards with Alignment, at the last Standards Committee (SC) meeting, appointed the standards drafting team. The standards development project had its kick-off meeting August 1-2, 2018. A Webinar is planned for August 14, 2018. Anticipate presenting the documents to the SC on August 23, 2018 with a request for authorization to post initially.	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	N/A	
P81 Req (2013)		
Number of Directives		
No. of Guidances (see Note 2)		
Directionally consistent with IERP findings (See Note 5)		
Developer	Laura Anderson	
PMOS Liaison	Mike Brytowski	
Affected Standards		
Last Updated	8/20/2018	

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 / PR	8/1/2017	8/14/2017	8/1/2017	8/14/2017			
Nominations - DT	5/1/2018	5/14/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2017	8/30/2017	8/1/2017	8/30/2017			
SP2 - SAR/PR/WP Posting 2	12/11/2017	1/9/2018	12/7/2017	1/6/2018	(4)		
CP1 - Comment Period 1	2/1/2018	3/2/2018	2/1/2018	3/2/2018			
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	9/17/2018	11/1/2018	9/17/2018	11/1/2018			
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	12/4/2018	12/14/2018	12/4/2018	12/14/2018			
PTB - Present to BOT	2/5/2018	2/8/2018	2/5/2018	2/8/2018			
Filing - Filing with Regulators	3/7/2018	3/10/2018	3/7/2018	3/10/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.
SC Action	6/13/2018	SC appoint drafting team as recommended by NERC staff.
Accept Baseline	9/13/2018	PMOS accepted based line.

Project	**2018-01**	**Home**
Project Name	Canadian-specific Revisions to TPL-007-2	
Status	Posted	
Comments	The SDT met July 31- August 1, 2018 in Montreal, Quebec to craft changes to the TPL-007-2 standard. The standard is posted through September 6, 2018.	
Deliverable	TPL-007-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	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	Mat Bunch	
PMOS Liaison	Charles Yeung	
Affected Standards	TPL-007-2	
Last Updated	8/20/2018	

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 / PR	3/30/2018	4/19/2018					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/30/2018	4/30/2018	3/30/2018	4/30/2018			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	***8/10/2018***	***9/6/2018***	***8/10/2018***	***9/9/2018***			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	10/5/2018	11/19/2018	10/5/2018	11/19/2018			
CAB - Com/Add Ballot 2	12/6/2018	1/20/2019	12/6/2018	1/20/2019			
CAB - Com/Add Ballot 3							

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/24/2019	2/3/2019	1/24/2019	2/3/2019			
PTB - Present to BOT	5/4/2019	5/5/2019	5/4/2019	5/5/2019			
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	4/25/2018	C. Yeung acccept to follow project.
Accept baseline schedule	9/13/2018	TBD - PMOS meeting after SDT meets.

Project	**2018-02**	**Home**
Project Name	Modifications to CIP-008 Cyber Security Incident Reporting	
Status	Nominations & SAR	
Comments	A nomination period for Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting standard drafting team members is open through 8 p.m. Eastern, Wednesday, August 29, 2018. An informal comment period for the Standard Authorization Request is open through 8 p.m. Eastern, Monday, September 10, 2018.	
Deliverable	CIP-008-6	
Deadline	1/19/2019	
Priority in RSDP, click to see applicable Footnote	High	
P81 Req (2013)	N/A	
Number of Directives	Order No. 848 (1 Directive, 4 elements)	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Alison Oswald	
PMOS Liaison	TBD	
Affected Standards	CIP-008-5	
Last Updated	8/21/2018	

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 / PR	***8/10/2018***	***8/29/2018***					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	***8/10/2018***	***9/10/2018***					
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
SC Action	8/9/2018	SCEC authorized posting of the SAR and solicitation of nominations.
Project added to PTS	8/10/2018	Added project for tracking by PMOS.
Assign PMOS Liaison	9/13/2018	PMOS appointed XXXXXX to the project.

No.	Description
Note 1	**2015-2017 RSDP** 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. Archived-Current - Project completed or abandoned. Archived-Baseline - Project completed or abandoned. Open-Baseline - Reserved for future project. Open-Current - Reserved for future project. N/A - Scheduling is not applicable.

Note 7	**2016-2018 RSDP** The following projects are planned to continue from 2015 along with any 2015 projects that are planned to be completed in that year but need additional time. As in the 2015–2017 RSDP, the approach to prioritizing Reliability Standards projects in this RSDP addressed 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). The prioritization gave primary consideration to 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.
Note 8	**2017-2019 RSDP** 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.
Note 9	2018-2020 RSDP (DRAFT)
Note 10	

RSC Meeting #18-3, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Mike Jones, Quintin and Herb Schrayshuen volunteered to assist Guy Zito and Ruida Shu on reviewing the NPCC RSPM	Guy Zito	By end of the year	Pending

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards, Compliance, and Enforcement Bulletin

August 13–19, 2018

INSIDE THIS EDITION

Active Standards Postings | Other Active Comment Periods | Standards News | General Compliance and Enforcement News | Other News | Standards Subject to Future Enforcement | Board of Trustees and FERC Action | Upcoming Events | About the SC&E Bulletin

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Final Ballot	08/03/18	08/13/18
Project 2015-10 – Single Points of Failure | TPL-001-5 and Implementation Plan	Additional Ballots and Non-binding Poll	08/31/18	09/14/18
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
--	--	--	--
Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
NEW Draft 2019–2021 Reliability Standards Development Plan	Comment Period	08/08/18	08/31/18

NEW Project 2018-01 – Canadian-specific Revisions to TPL-007-2 | Proposed TPL-007-2 Canadian Variance	Comment Period	08/10/18	09/06/18
NEW 2018 Bulk Electric System Definition Reference Document	Comment Period	08/07/18	09/10/18
NEW Project 2018-02 – Modifications to CIP-008 Cyber Security Incident Reporting | Standard Authorization Request	Comment Period	08/10/19	09/10/18
Project 2015-10 – Single Points of Failure | TPL-001-5 and Implementation Plan	Comment Period	07/30/18	09/14/18
Functional Model Advisory Group | Reliability Functional Model and Functional Model Technical Document	Comment Period	08/03/18	09/17/18

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Version 3.0 of the Generating Unit Operations during Complete Loss of Communications Draft Reliability Guideline: Reliability Guidelines provide suggested guidance on a particular topic for use by BPS users, owners, and operators according to each entity's circumstances. The NERC Operating Committee (OC) charter requires Reliability Guidelines to be refreshed every three years. Redlined and clean drafts of the Reliability Guideline: Generating Unit Operations during Complete Loss of Communications - Version 3.0 have been posted on the NERC website for industry comment.	Submit comments via email using the comment form.	07/13/18	08/27/18

STANDARDS NEWS

NEW Nomination Period Open for Project 2018-02 – Modifications to CIP-008 Cyber Security Incident Reporting Standard Drafting Team Members

Nominations are being sought for standard drafting team (SDT) members for Project 2018-02 – Modifications to CIP-008 Cyber Security Incident Reporting through August 29, 2018.

Use the electronic form to submit a nomination. If you experience issues using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Drafting Team Vacancies page and the project page.

Quick Links

- Register in the SBS
- Projected Standards Posting Schedule
- Project Tracking Spreadsheet
- Standards Related Questions – Single Portal
- 2017–2019 Reliability Standards Development Plan
- Quality Review Application
- One-Stop Shop (Status, Purpose, Implementation Plans, FERC Orders, RSAWs)

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

A significant time commitment is expected of SDT members to meet the six-month regulatory deadline established in Order No. 848. SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately three face-to-face meetings between September and December 2018 (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Due to the expedited timeline on this project, please be prepared for an initial meeting at the end of September 2018.

NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas:

- Critical Infrastructure Protection (CIP) family of Reliability Standards;
- Incident reporting;
- Cyber Asset and BES Cyber Asset definitions; and/or
- Electricity Information Sharing and Analysis Center (E-ISAC) and the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT).

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information. The Standards Committee is expected to appoint members to the team mid-September 2018. Nominees will be notified after they have been selected.

Updated Links for Affected Reliability Standards

Due to recent server changes, links to the following Reliability Standards have been updated on the U.S. Effective Dates page:

Affected Reliability Standards			
BAL-005-0.2b	IRO-006-TRE-1	MOD-020-0	PRC-008-0
BAL-006-2	IRO-006-WECC-2	MOD-025-2	PRC-011-0
FAC-013-2	MOD-001-1a	PER-003-1	PRC-018-1
IRO-006-5	MOD-008-1	PRC-006-NPCC-1	

If you encounter difficulties accessing any Reliability Standards on the US Effective Dates page, please send an email to sarcomm@nerc.net.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Issues and Recommendations Tracking Spreadsheet Updated

On August 7, 2018, the Issues and Recommendations Tracking spreadsheet on the ERO Enterprise Program Alignment page was updated.

Quick Links

- Risk-Based CMEP
- CIP V5 Transition Program
- ERO Enterprise Program Alignment Process
- Consistency Reporting Tool (EthicsPoint)
- Risk-Based Registration Initiative
- Reliability Standard Audit Worksheets
- Enforcement & Mitigation: Enforcement Actions
- CMEP Technology Project

OTHER NEWS

NEW Lessons Learned Posted

Two new lessons learned have been posted on the NERC website on the Lessons Learned page. Additional lessons learned are available in the September 2017 Hurricane Irma Event Analysis Report. The new lessons address the following topics:

- Firewall Failure After Time Limit Exceeded
- Loss of Substation Data Circuits to SCADA

NEW Bill Lawrence Named Vice President and Chief Security Officer

NERC's Board of Trustees named Bill Lawrence as vice president and chief security officer, effective August 16. In his new role, Lawrence will lead all of NERC's security programs executed through the Electricity Information Sharing and Analysis Center (E-ISAC) operations, directing security risk assessments and mitigation initiatives to protect critical electricity infrastructure across North America. Lawrence will also lead coordination efforts with government agencies and stakeholders on cyber and physical security matters, including analysis, response and sharing of critical sector information.

Cyber and physical security are top risk priorities for NERC President and Chief Executive Officer Jim Robb, who oversaw the nationwide search for the right executive to lead the programs executed through the E-ISAC. For more information, please see the full announcement.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Effective Date	Standard(s)
September 1, 2018	--
January 1, 2019	BAL-005-1 – Balancing Authority Control
	FAC-001-3 – Facility Interconnection Requirements
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5, 5.1–5.2)
April 1, 2019	EOP-004-4 – Event Reporting

	EOP-005-3 – System Restoration from Blackstart Resources EOP-006-3 – System Restoration Coordination EOP-008-2 – Loss of Control Center Functionality
January 1, 2020	CIP-003-7 – Cyber Security — Security Management Controls
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
July 1, 2020	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
October 1, 2020	PER-006-1 – Specific Training for Personnel
	PRC-027-1 – Coordination of Protection Systems for Performance During Faults
January 1, 2021	PRC-012-2 – Remedial Action Schemes
	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 (100% compliance for Requirements 2–4, 6–11)

BOARD OF TRUSTEES AND FERC ACTION

UPDATED NERC Board of Trustees Meeting Agenda Packages, Presentations, Policy Input, Schedule of Events, and Letter of Recognition for Canadian Border Services Posted

Agenda packages for the Board of Trustees, Compliance Committee, Member Representatives Committee, Corporate Governance and Human Resources Committee, Technology and Security Committee, and Finance and Audit Committee meetings on August 15–16, 2018 in Calgary, Canada are available.

Presentations for the Board of Trustees, Compliance Committee, Member Representatives Committee, and Corporate Governance and Human Resources Committee.

The schedule of events, policy input document, and a letter of recognition for the Canadian Border Services Agency are also available.

NEW NERC Filings

On August 7, 2018, NERC submitted to FERC a supplemental filing, providing additional information to the NERC informational filing submitted to FERC on June 29, 2018.

NERC's 2018 filings to FERC are available here.

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

- Monitoring and Situational Awareness Technical Conference – October 2–3, 2018, Carmel, Indiana | Register | Hotel Registration | Presentations from Previous Conferences
- GridSecCon 2018 – October 15–19, 2018, Las Vegas, Nevada | Register

Webinars

- Winter Preparation for Severe Cold Weather webinar – 2:00–3:00 p.m. Eastern, September 6, 2018 | Register

Standing Committee Meetings and Conference Calls

- Board of Trustees Committees, Members Representatives Committee, and Board of Trustees Meetings – August 15–16, 2018, Calgary, Canada | Meeting Registration and Hotel Information
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – September 11–12, 2018, Minneapolis, Minnesota | Register for OC | Register for PC | Register for CIPC | Register for Hotel

Standard Drafting Team Meetings and Conference Calls

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.

- NEW Project 2018-0 1 – Canadian-specific Revisions to TPL-007-2 Drafting Team Meeting – September 11–12, 2018, Toronto, Ontario | Register

ABOUT THE STANDARDS, COMPLIANCE, AND ENFORCEMENT BULLETIN

This weekly bulletin compiles a list of standards, compliance, and enforcement 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.

If you would like to receive this bulletin or be added to the distribution list for a particular project, please contact Sandy Shiflett. For more information about any of the compliance news listed in the bulletin, please contact Tiffany Whaley.

Northeast Power Coordinating Council, Inc. Regional Standards Committee

2018 North American Regulatory Utility Commissioners Summer Policy Summit

Guy V. Zito

NPCC AVP - Standards

IEEE 1547 DER Performance and Frequency Ride-Through

- DER Challenges – reverse power flow and lack of controllability, observability, and interoperability of the Distribution-Transmission interface.

Four steps to implementing IEEE 1547:

- Update interconnection standards accordingly
- Understand all the capabilities and limitations of the new DER and 1547
- Deploy sufficient communication networks (all new DER have communication capabilities)
- Integrate into markets and operations

Canadian Regulatory and CAMPUT

Canada's National Energy Board (not the equivalent of FERC) - they don't regulate interprovincial energy transfer within Canada. Reported that the majority of energy transfer is from north to south into the US and that interprovincial transfers were minimal. NEB regulates:

- Interprovincial and International pipelines (audits, lifecycle regulatory and maintenance)
- Tolls and Tariffs
- Construction and Operation of International power lines
- Exporting and Importing of Energy for Canada

Canadian Regulatory and CAMPUT (cont.)

NEB modernization legislation:

- All new projects subject to impact assessment
- Integrated review at time of impact assessment
- Offshore renewable energy requirements
- Increase public engagement (engage indigenous communities early in process)
- Lifecycle regulation will continue
- Bill currently in Canada Senate for approval in Sept 2018

Department of Energy Remarks

- Investments in Cyber Security lacking and methods severly outdated.
- Encouraged Commissioners to allow proper recovery of investments for cyber security
- Seek risk based solutions to risk informed problems
- Incorporation into rate determinations is critical.
- Emphasized national security importance of Cyber and mentioned protection against Electro-Magnetic Pulse(EMP).

Energy Water Nexus

- Create an IT architecture capable of processing big data from water and energy SCADA systems
- Initially develop smaller projects that may be scaled up as lessons are learned
- Change the culture internally of Energy and Water companies
- Create incentives to encourage participation within and between organizations to promote new ideas and goals
- Incentivize the private sector to make investments, broaden benefits and more evenly distribute risk to those that benefit.

Blockchain

Initially developed for crypto currencies and Initial Coin Offerings (ICO). :

- Distributed ledger with no central market.
- Peer to peer network and difficult to hack however as transactional limitation related to speed.
- Establishes trust and contains information in each block that must be verified by all users of the network to be deemed valid.
- Potential applications in Energy will be to allow a customer to bid out their individual load profile.
- This will be extremely impactful in the future to regulatory processes.

Transactive Energy

- May utilize Blockchain technology
- Utilizes distributed energy nodes rather than traditional hierarchal grid structure.
- Interoperability refers to the ability of involved systems to connect and exchange energy information to enable interoperability of generation sources and consumption
- Uses economic or market based constructs while maintaining limits and constraints on the electrical grid in an automated manner.
- Exponentially more complex – millions of nodes on the Distribution side vs. controlling a few generation plants- there are some pilots underway (e.g. Buffalo University at Niagara)

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FERC Order 841 Energy Storage

- Remove barriers for energy storage to participate in energy and ancillary service markets to support resilience.
- The Order is meant to level the playing field in the ISO/RTO wholesale markets.
- Storage is expected to increase in excess of five-fold in the next decade.
- Southern Company over 5000MWHrs of storage on their system that is routinely called on (2 pump storage facilities) Large amounts of intermittent resources will require large amounts of storage, and all stakeholders should have the opportunity to own storage
- APS reported that a storage facility installed in their territory replaced the need to upgrade a transmission line that was forecast to experience overloads for only short time periods

FERC Order 841 Energy Storage

- Lithium Ion (Li-ion) 4 hour capability.
- Li-ion costs have been reduced by 80% since their inception. They are produced globally so price will continue to be reduced.
- 35 GW on the system by 2025 and over 50 GW in a decade.
- Significant reliability benefit- instantaneous ramping, voltage support etc.
- Regulator questions-costs of storage vs. Generation vs. Demand Side efficiency programs will determine choice of solution to an issue.
- National Grid's system of a new 5 MW 8 hour Li-ion battery was mentioned. It is a joint project with NextEra, new design high performance Li-ion battery.

Southwest Water Crisis

- Lake Meade -Hoover Dam reported to be down over 175 feet
- Severe water restrictions will take effect in 2019
- New proposed thermal plants will have to specifically state their water needs- No new thermal plants that use water should be built in the southwest.
- Renewables saved in excess of 95 billion gallons of water thusfar in the southwest.
- Increased pressure on thermal plants to use reclaimed water (effluent) for cooling. The Palo Verde nuclear plant is now using effluent.
- APS noted Arizona lost the bid for Amazon's Headquarters because of the inability to supply it with 100% renewable energy.
- Pipeline from Mississippi(?)

Gas Electric Interdependencies

- MA. Commissioner-13 days last winter- in excess of 2 million gallons of oil burned to make up for gas shortfalls and pipeline constraints
- Study on fuel security done by ISO-NE mentioned and that 19 of the 23 scenarios studies showed the potential for capacity deficiency and load shedding. Study did not consider any new pipeline capacity in service.
- PA Commissioner abundant supply of Gas and a new shale find thousands of wells are capped due to low prices. The need for more pipeline infrastructure is critical.

Gas Electric Interdependencies (cont.)

- PJM Andy Ott President and CEO- no critical resilience emergency or threat, PJM was conducting a resilience study/assessment and that if gas was interrupted, 50 % of their capacity could be served by oil. Also stated that PJM markets currently support a satisfactory level of resilience.
- The panel noted that there were approximately 60 operating Nuclear units, of which only 80% received any form of subsidy. The markets need to address this.

Key Major Takeaways:

- DER was a major theme however, depending on the state, the Commissioners placed different importance on it.
- Commissioners in the Northeast – more wary of widespread DER penetration
- Concerns about Cyber and how much customers are willing to pay
- Concerns about resilience-different perspectives
- Storage will be increasingly important and widespread
- Expect increases in community solar
- Less emphasis on transmission solutions going forward
- Transactive Energy will create the need to change regulatory structure-new types of markets and Blockchain will develop

“Intelligence is the ability to adapt to change.”-
Stephen Hawking

Questions or Comments ?

NARUC Summer Policy Summit

July 15–18, 2018

#NARUCSummer18 • Wi-Fi Access Code: NARUCAZ18

See the complete agenda on the NARUC meeting app.

SUNDAY

8:00 a.m.–6:30 p.m.	**Registration**	
8:30 a.m.–4:00 p.m.	**Staff Subcommittee on Telecommunications**	**Palomino 1 & 2**
9:00 a.m.–11:45 a.m.	**Staff Subcommittee on Energy Resources and the Environment**	**Palomino 4 & 5**
9:00 a.m.–11:45 a.m.	**Subcommittee on Supplier and Workforce Diversity**	**Palomino 8–10**
9:00 a.m.–11:45 a.m.	**Staff Subcommittee on Consumers and the Public Interest** (Closed Meeting 9:00 a.m.–10:15 a.m.)	**Arabian / Palomino 4 & 5**
9:00 a.m.–11:45 a.m.	**Staff Subcommittee on Rate Design**	**Palomino 6 & 7**
9:00 a.m.–11:45 a.m.	**Staff Subcommittee on Water**	**Palomino 6 & 7**
9:00 a.m.–10:15 a.m. and 3:30 p.m.–4:45 p.m.	**Staff Subcommittee on Electricity**	**Palomino 4 & 5 / Palomino 8–10**
9:00 a.m.–10:15 a.m. and 3:30 p.m.–4:45 p.m.	**Staff Subcommittee on Electric Reliability**	**Palomino 4 & 5 / Palomino 8–10**
10:00 a.m.–11:45 a.m.	**Washington Action** (Closed Meeting)	**Moor 3**
10:15 a.m.–10:30 a.m.	**Networking Break**	**Foyer**
10:30 a.m.–11:45 a.m.	**Staff Subcommittee on Critical Infrastructure** (Closed Meeting)	**Arabian**
11:00 a.m.–1:00 p.m.	**New Commissioner Forum** (New Commissioners Only)	**Dorado**
1:30 p.m.–5:00 p.m.	**Committee on International Relations**	**Palomino 6 & 7**
1:30 p.m.–5:00 p.m.	**Committee on Critical Infrastructure**	**Palomino 8–10**
1:30 p.m.–5:00 p.m.	**Staff Subcommittee on Gas**	**Palomino 3**
1:30 p.m.–5:30 p.m.	**Staff Subcommittee on Pipeline Safety**	**Palomino 3**
2:30 p.m.–4:30 p.m.	**Staff Subcommittee on Executive Management** (Closed Meeting)	**Moor 3**
2:30 p.m.–4:30 p.m.	**Staff Subcommittee on Information Services** (Closed Meeting)	**Moor 3**
2:30 p.m.–3:00 p.m.	**Networking Break**	**Foyer**
3:30 p.m.–4:45 p.m.	**Committee on Electricity**	**Palomino 8–10**
3:30 p.m.–5:00 p.m.	**Committee on Consumers and the Public Interest** (Closed Business Meeting)	**Arabian**
3:30 p.m.–5:00 p.m.	**Committee on Energy Resources and the Environment**	**Palomino 8–10**
3:45 p.m.–4:00 p.m.	**Networking Break**	**Foyer**
5:00 p.m.–6:30 p.m.	**Welcome Reception**	**Princess Ballroom**

MONDAY

6:30 a.m.–8:15 a.m.	**OPSI Breakfast**	**Princess Salon C**
8:30 a.m.–5:00 p.m.	**Registration**	
8:30 a.m.–10:15 a.m.	**General Session** • **Welcome to the NARUC Summer Policy Summit in Scottsdale** • **Advancing Reliability and Resiliency in the Electric Power System** • **How to Create and Implement an Innovative Ecosystem in the Water and Energy Nexus**	**Princess Ballroom**
10:15 a.m.–10:30 a.m.	**Networking Break**	**Foyer**
10:30 a.m.–5:00 p.m.	**Committee on Electricity**	**Palomino 4 & 5**
10:45 a.m.–2:30 p.m.	**Task Force on Innovation**	**Palomino 8–10 / Palomino 4 & 5**
10:45 a.m.–3:45 p.m.	**Committee on Consumers and the Public Interest**	**Palomino 4 & 5 / Palomino 1 & 2**
10:45 a.m.–5:00 p.m.	**Committee on Energy Resources and the Environment**	**Palomino 8–10 / Palomino 4 & 5**
10:45 a.m.–5:00 p.m.	**Committee on Gas**	**Palomino 4 & 5 / Palomino 6 & 7**
10:45 a.m.–5:00 p.m.	**Committee on Telecommunications**	**Palomino 1 & 2**
10:45 a.m.–5:00 p.m.	**Committee on Water**	**Palomino 3**
1:30 p.m.–2:30 p.m.	**Committee on Critical Infrastructure**	**Palomino 6 & 7**
1:30 p.m.–2:30 p.m.	**Subcommittee on Pipeline Safety**	**Palomino 6 & 7**
1:30 p.m.–2:30 p.m.	**Subcommittee on Supplier and Workforce Diversity**	**Palomino 8–10**
2:30 p.m.–2:45 p.m.	**Networking Break**	**Foyer**
3:45 p.m.–4:00 p.m.	**Networking Break**	**Foyer**
5:15 p.m.–6:15 p.m.	**Commission Staff Power Hour** (Commission Staff Only)	**Princess Salon A–C**
5:15 p.m.–6:00 p.m.	**MACRUC Regional Meeting** (Invitees Only)	**Moor 2**
5:15 p.m.–6:00 p.m.	**MARC Regional Meeting** (Invitees Only)	**Arabian**
5:15 p.m.–6:00 p.m.	**SEARUC Regional Meeting** (Invitees Only)	**Golden**
5:15 p.m.–6:00 p.m.	**Western Regional Meeting** (Invitees Only)	**Moor 3**

TUESDAY

8:30 a.m.–4:00 p.m.	**Registration**	
9:00 a.m.–10:15 a.m.	**General Session** **Like the Deserts Miss the Rain: Understanding the Energy-Water Nexus in the Desert**	**Princess Ballroom**
10:15 a.m.–10:30 a.m.	**Networking Break**	**Foyer**
10:45 a.m.–3:45 p.m.	**Task Force on Innovation**	**Palomino 3 / Palomino 6 & 7**
10:45 a.m.–11:45 a.m.	**Committee on Consumers and the Public Interest**	**Palomino 8–10**
10:45 a.m.–5:00 p.m.	**Committee on Electricity**	**Palomino 4 & 5**
10:45 a.m.–5:00 p.m.	**Committee on Energy Resources and the Environment**	**Palomino 8–10**
10:45 a.m.–5:00 p.m.	**Committee on Gas** (Closed Meeting 1:30–2:30 and 4:00–5:00)	**Palomino 4 & 5 / Palomino 6 & 7**
10:45 a.m.–5:00 p.m.	**Committee on Telecommunications**	**Palomino 1 & 2**
10:45 a.m.–5:00 p.m.	**Committee on Water**	**Palomino 3**
11:45 a.m.–1:15 p.m.	**Commissioner Emeritus Lunch**	**Princess Salon C**
11:45 a.m.–1:15 p.m.	**Commissioner Only Lunch**	**Princess Salon A & B**
1:30 p.m.–2:30 p.m.	**Subcommittee on Pipeline Safety** (Closed Meeting)	**Palomino 6 & 7**
1:30 p.m.–2:30 p.m.	**Staff Subcommittee on Pipeline Safety** (Closed Meeting)	**Palomino 6 & 7**
2:30 p.m.–2:45 p.m.	**Networking Break**	**Foyer**
2:45 p.m.–5:00 p.m.	**Subcommittee on Nuclear Issues—Waste Disposal**	**Palomino 4 & 5**
3:45 p.m.–4:00 p.m.	**Networking Break**	**Foyer**
2:45 p.m.–5:00 p.m.	**Subcommitttee on Clean Coal and Carbon Management**	**Palomino 4 & 5**

WEDNESDAY

9:00 a.m.–11:45 a.m.	**Registration**	
9:00 a.m.–10:15 a.m.	**General Session** **Regulatory Yoga: Are We Flexible Enough?**	**Princess Ballroom**
10:15 a.m.–10:30 a.m.	**Networking Break**	**Foyer**
10:30 a.m.–11:30 a.m.	**General Session** **Advocacy Update: There's Bite in Our Bark**	**Princess Ballroom**
11:45 a.m.–2:00 p.m.	**Board of Directors Meeting**	**Princess A–C**

National Association of Regulatory Utility Commissioners "NARUC", Summer 2018 Policy Summit

IEEE 1547 -new requirements for DER performance and frequency ride through. Germany's experience with DER due to industry leadership and early implementation- 300,000 DER's needed to be retrofitted at a cost of 10s of millions of Euros as problems were found and issues needed to be addressed. Not meant for residential, transmission, or substation and is a "distribution only" standard. While the standard is technically neutral there are default settings for equipment. Very important to coordinate DER settings with individual distribution protection settings. Reported that inverter manufacturers will take a year to be fully compliant with the approved 1547 standard. After that, another version of 1547 will be developed to add in testing and maintenance requirements. Noted that ISO-NE has a stakeholder program to implement 1547.

DER Challenges – reverse power flow and lack of controllability, observability and interoperability of the Dist-trans interface

Four steps to implementing IEEE1547:

- Update interconnection standards accordingly
- Understand all the capabilities and limitations of the new DER and 1547
- Deploy sufficient communication networks (all new DER have communication capabilities)
- Integrate into markets and operations

Community Solar- 19 states have policies specific to community solar installations. All of the Northeast states have a policy in NPCC. Special rates and credits are available to encourage participation. Concern expressed that low income don't have access due to demographics and initial fees.

Energy Storage- 36 States have appreciable storage on the system. All of NPCC. Storage is being considered in integrated resource planning and a viable alternative to generation.

Arizona Public Service reported 1.6 GW of DER. 1 in 17 homes has rooftop solar and most use less than half they are cable of generating.

CAMPUT and Canadian Regulators-10 Provinces and next CAMPUT meeting in Calgary in 2019.

Canada's National Energy Board (not the equivalent of FERC) - they don't regulate interprovincial energy transfer within Canada. Reported that the majority of energy transfer is from north to south into the US and that interprovincial transfers were minimal. Therefor NEB regulates:

- Interprovincial and International pipelines (audits, lifecycle regulatory and maintenance)
- Tolls and Tariffs
- Construction and Operation of International power lines
- Exporting and Importing of Energy for Canada

NEB modernization legislation:

- All new projects subject to impact assessment
- Integrated review at time of impact assessment
- Offshore renewable energy requirements
- Increase public engagement (engage indigenous communities early in process)
- Lifecycle regulation will continue
- Bill currently in Canada Senate for approval in Sept 2018

General Session, Deputy Director Walker, DOE- by video-Investments in Cyber Security lacking and methods outdated. Encouraged Commissioners to allow proper recovery of investments for cyber and seek risk based solutions. Incorporation into rate determinations is critical. Emphasized national security importance of Cyber and mentioned protection against Electro-Magnetic Pulse(EMP).

Energy-Water Nexus –Ecosystem of Innovation

Discussions of improving efficient operation of energy and water systems. Opportunity to coordinate energy usage with water usage (pumping and flow). Idaho stated that good coordination of water-electric SCADA system data and development of algorithms resulted in 10% less electric costs and reductions in the need to train water operators from 4 years to 6 months. Recommendations / requirements to create an efficient and effective Energy Water nexus were:

- Create an IT architecture capable of processing big data from water and energy SCADA systems
- Initially develop smaller projects that may be scaled up as lessons are learned
- Change the culture internally of Energy and Water companies
- Create incentives to encourage participation within and between organizations to promote new ideas and goals
- Incentivize the private sector to make investments, broaden benefits and more evenly distribut risk to those that benefit.

Blockchain and Transactive Energy

Blockchain is a distributed ledger with no central market. It is a peer to peer network and difficult to hack however as transactional limitation related to speed. Blockchain establishes trust and contains information in each block that must be verified by all users of the network to be deemed valid. Initially developed for crypto currencies and Initial Coin Offerings (ICO). Potential applications in Energy will be to allow a customer to bid out their individual load profile. This will be extremely impactful in the future to regulatory processes.

Transactive Energy may utilize Blockchain technology and utilizes distributed energy nodes. It relies on communication of information to enable interoperability of generation sources and consumption to maintain limits and constraints on the electrical grid in an automated manner. There are some pilots underway. Buffalo University at Niagara was mentioned.

Engaging customers in the process of grid transformation during the cost benefit discussions of investments, use of performance based rates will be important. As DERs and energy interoperability technology improves what value will further transmission investment and how will it be measured?

FERC Order 841 Energy Storage- Remove barriers for energy storage to participate in energy and ancillary service markets to support resilience. The Order is meant to level the playing field in the ISO/RTO wholesale markets. Storage is expected to increase in excess of five-fold in the next decade.

Southern Company reported that they have over 5000MWHrs of storage on their system that is routinely called on. They have 2 pump storage facilities. The value of the storage is dependent on the system resource mix. Reported that the business ownership and value model will be unique for each state. Large amounts of intermittent resources will require large amounts of storage, and all stakeholders should have the opportunity to own storage.

North Carolina municipal- Residential battery program will be in place next year. No storage for solar yet at this time.

Arizona Public Service reported that a storage facility installed in their territory replaced the need to upgrade a transmission line that was forcast to experience overloads for only short time periods.

General agreement that storage need was very specific and the type needed to be matched to the situation it was being implemented for. For instance, Lithium Ion (Li-ion) has only about a 4 hour capability. It was reported that Li-ion costs have been reduced by 80% since their inception. They are produced globally so price will continue to be reduced. It is estimated that will be 35 GW on the system by 2025 and over 50 GW in a decade. Proponents ascertain they provide multiple layers of value, flexibility, and provide ancillary services. They add significant reliability benefit, instantaneous ramping, voltage support etc. Regulator questions however will continue, - how costs of storage vs. Generation vs. Demand Side efficiency programs will determine choice of solution to an issue. A project on National Grid's system of a new 5 MW 8 hour Li-ion battery was mentioned. It is a joint project with NextEra, no details were given however this is a new design high performance Li-ion battery.

Southwest Water Crisis

Lake Meade behind the Hoover Dam reported to be down over 175 feet. Severe water restrictions will take effect in 2019. New proposed thermal plants will have to specifically state their water needs. Mention made that No new thermal plants that use water should be built in the southwest. It was reported that renewables saved in excess of 95 billion gallons of water thusfar in the southwest. Water use will become increasingly important in obtaining the Certificate of Environmental Compliance. Increased pressure on thermal plants to use reclaimed water (effluent) for cooling. Also effluent is being used to recharge ground water. The Palo Verde nuclear plant is now using effluent.

APS noted Arizona lost the bid for Amazon's Headquarters because of the inability to supply it with 100% renewable energy. This will be an increasing problem going forward, as more major corporations will want the optics of being "green."

Situation of drought in the Southwest will only worsen, according to meteorologists. Arizona Commissioner mentioned they are looking at the feasibility of a project to install a pipeline from the Mississippi River to the southwest. Agricultural rights will be the first to be cut if the Colorado River flow reduces further. Also, new building permits may begin to be denied or restricted. Grey water capable plumbing may be required for new homes.

Gas Electric Interdependencies

MA. Commissioner stated during a period of 13 days in the last winter period there were in excess of 2 million gallons of oil burned to make up for gas shortfalls and pipeline constraints. FERC Order on the Mystic Units and Distrigas mentioned. Study on fuel security done by ISO-NE mentioned and that 19 of the 23 scenarios studies showed the potential for capacity deficiency. Study did not consider any new pipeline capacity in service.

PA Commissioner stated that there is an abundant supply of Gas and a new shale find. Stated that there is such an oversupply that thousands of wells are capped due to low prices. The need for more pipeline infrastructure is critical.

PJM Andy Ott(?) President and CEO- Sees no critical resilience emergency or threat. Did, after Commissioner pressure, admit there was a "problem" going forward. Stated that PJM was conducting a resilience study/assessment and that if gas was interrupted, 50 % of their capacity could be served by oil. Also stated that PJM markets currently support a satisfactory level of resilience.

The panel noted that there were approximately 60 operating Nuclear units, of which only 80% received any form of subsidy. The markets need to address this.

Section 202(c) When the President says "NO" to retirements

Panel on clean coal and Nuclear- Proponents maintain clean coal with Carbon Capture and Sequestion is still a viable option. Side benefit is during coal mining, rare earth elements are also mined which reduces our dependence on these elements from Russia. Noted that Wyoming produces 40% of the coal in the US, more than any other states. Carbon capture and sequestion is leading to production of Active Carbon development activities used in water filtration. Commissioners had concern about retirements of base load generation. Administration wants to protect the "backbone" of the electric system and not properly valued. DOE using the "Defense Production Authorization Act" to protect these assets and maximize the use of these assets for energy supply defense.

It was noted that Nuclear facilities in NJ save customers $400M/yr but were not accurately priced.

DOE set to issue issue an Order under Section 203(c) which will allow DOE/FERC to continue operation of necessary facilities and receive sufficient cost recovery(speaker admitted that cost recovery was difficult to determine). Authority under this section was used during the California blackouts, for the Cross Sound Cable from CT to Long Island NY, and for a coal plant in VA that supplied Washington DC. It was stated that ISO/RTOs will be mandated to purchase electricity at cost recovery rates, prevent the

retirements for a period of 24 months from a list of Generating units. This list of Generators, deemed necessary for defense and national security will be determined by the DOE and disallowed to be retired.

In synopsis, DER was a major theme however, depending on the state, the Commissioners placed different importance on it. Southwest was the most supportive, primarily due to the water issues. Other Commissioners from states where gas was in a greater supply seemed to be more wary of overpenetration of DER and concerned with resilience. All were concerned with Cyber and how to incorporate that into rates that consumers would have to pay.

Northeast Power Coordinating Council, Inc. Regional Standards Committee

FERC Orders and NOPRs of Interest

Guy V. Zito
NPCC AVP - Standards

FERC – Orders and Notice of Proposed Rulemakings (NOPRs):

- FERC -GMD NOPR TPL-007-2
- FERC –Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators
- FERC –Order 848, Cyber Security Incident Reporting Reliability Standards
- FERC –Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines

FERC -GMD NOPR TPL-007-2

FERC Directed NERC to revise TPL-007-1 to address the following:

(1) conduct supplemental GMD vulnerability assessments and thermal impact assessments;

(2) obtain GIC and magnetometer data; and

(3) meet certain deadlines for the development and completion of tasks in corrective action plans

FERC proposes to approve TPL-007-2 and file a revision within 12 months to include include:

- require applicable entities to develop and implement corrective action plans to mitigate vulnerabilities revealed by conducting supplemental GMD vulnerability assessments

FERC -GMD NOPR TPL-007-2, (cont.)

FERC seeking comment on two options to address concern of entities exceeding deadlines for completing CAPs:

- Option 1 NERC develops a review process whereby NERC considers extensions on a case-by-case basis
- Option 2 the Commission would approve proposed Requirement R7.4 (circumstances beyond an entity's control-redocument CAP every 12 months)

Under both Options, FERC would require NERC to prepare and submit a report regarding how often and why applicable entities are exceeding corrective action plan deadlines following implementation of the proposed Reliability Standard. (how would NERC get the information?)

FERC –Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

FERC has ruled that within the US each RTO and ISO shall revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets

FERC –Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (cont.)

The Participation Model must:

(1) ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing in the RTO/ISO markets;

(2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price;

FERC –Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (cont.)

(3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and

(4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW

- Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price

FERC –Order 848, Cyber Security Incident Reporting Reliability Standards

Order issued July 19, 2018-(Effective 60 days after FR)

"The Commission directs NERC to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS)."

Reason for order:

- The current reporting threshold may understate the true scope of cyber-related threats facing the Bulk-Power System, particularly given the lack of any reportable incidents in 2015 and 2016

FERC –Order 848, Cyber Security Incident Reporting Reliability Standards (cont.)

EACMS, includes firewalls, authentication servers, security event monitoring systems, IDS and alerting systems, control electronic access into the ESP and play a significant role in the protection of high and medium impact BES Cyber Systems. If the EACMS is compromised, an attacker could more easily enter the ESP and effectively control the BES Cyber System or Protected Cyber Asset.

Four elements of the Directive in the Order:

(1) responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS;

(2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information;

FERC –Order 848, Cyber Security Incident Reporting Reliability Standards (cont.)

Four elements of the Directive in the Order (cont.):

(3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and

(4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT).

FERC –Order 848, Cyber Security Incident Reporting Reliability Standards (cont.)

- NERC must also file an annual, public, and anonymized summary of the reports with the Commission.
- Stated intent is to achieve a measured broadening of the existing reporting requirement in Reliability Standard CIP-008-5, consistent with NERC's recommendation, rather than a wholesale change in cyber incident reporting
- Revision to CIP-008-5 is due for filing with the Commission no later than April 1, 2019
- Commission rejected Section 1600 data request option-standard is the appropriate mechanism
- SC-approve SAR for posting, solicit SDT members. New team, not the existing CIP Modifications SDT due to expedited schedule and volume of work for existing CIP team

FERC –Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines

- Issued July 2, 2018
- Request filed by ISO-NE requesting waiver of several tariff provisions which would permit ISO-NE to retain two retiring generating units owned by Exelon Generation Company, LLC (Exelon), Mystic 8 and 9, for fuel security purposes
- FERC denied waiver and preliminarily finds that ISO-NE's Tariff may be unjust and unreasonable, based on ISO-NE's demonstration that its Tariff fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022
- Exelon purchasing Distrigas-sole supplier of Mystic 8 and 9not subject to the region's historical interstate natural gas pipeline constraints.

FERC –Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines (cont.)

ISO-NE ordered to either:

(1) to submit within 60 days of the date of this order interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns; or

(2) within 60 days of the date of this order, to show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both filings is not necessary.

- FERC also is taking action *sua sponte (on its own motion)* to extend the deadline in two tariff provisions to enable Exelon to postpone its retirement decision regarding Mystic 8 and 9.

FERC –Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines (cont.)

FERC's determination if a submitted Waiver is valid relies on the following criteria:

(1) whether the applicant acted in good faith

(2) whether the waiver is of limited scope

(3) whether the waiver addresses a concrete problem; and

(4) whether the waiver does not have undesirable consequences, such as harming third parties.

“Intelligence is the ability to adapt to change.”-
Stephen Hawking

Questions or Comments ?

164 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM18-2-000; Order No. 848]

Cyber Security Incident Reporting Reliability Standards

(Issued July 19, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) directs the North American Electric Reliability Corporation (NERC) to develop and submit modifications to the NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the bulk electric system (BES).

DATES: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

164 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Kevin J. McIntyre, Chairman;
Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

Cyber Security Incident Reporting Reliability Standards Docket No. RM18-2-000

ORDER NO. 848

FINAL RULE

(Issued July 19, 2018)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA), the Commission directs the North American Electric Reliability Corporation (NERC) to develop and submit modifications to the NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES.[1] The Commission directs NERC to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible

[1] 16 U.S.C. 824o(d)(5). The NERC Glossary of Terms Used in NERC Reliability Standards (June 12, 2018) (NERC Glossary) defines a Cyber Security Incident as "A malicious act or suspicious event that: Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System."

entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS).[2]

2. In the NOPR, the Commission observed that Cyber Security Incidents are presently reported by responsible entities in accordance with Reliability Standard CIP-008-5 (Cyber Security – Incident Reporting and Response Planning).[3] However, under the definition of Reportable Cyber Security Incident in Reliability Standard CIP-008-5, responsible entities must only report Cyber Security Incidents if they have "compromised or disrupted one or more reliability tasks." The Commission explained that the current reporting threshold may understate the true scope of cyber-related threats facing the Bulk-Power System, particularly given the lack of any reportable incidents in 2015 and 2016. To improve awareness of existing and future cyber security threats and potential vulnerabilities, the Commission proposed to direct that NERC develop and submit modifications to the existing Reliability Standards to augment the reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES.

3. As discussed in detail below, the Commission adopts the NOPR proposal. The Commission's directive in this Final Rule consists of four elements intended to augment

[2] The NERC Glossary defines "ESP" as "[t]he logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." The NERC Glossary defines "EACMS" as "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems."

[3] *Cyber Security Incident Reporting Reliability Standards*, Notice of Proposed Rulemaking, 82 FR 61,499 (Dec. 28, 2017), 161 FERC ¶ 61,291, P 1 (2017) (NOPR).

the current Cyber Security Incident reporting requirement: (1) responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; (3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and (4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT). Further, NERC must file an annual, public, and anonymized summary of the reports with the Commission.

4. As discussed below, after considering the comments submitted in response to the NOPR, we conclude that the proposed directive to augment the current reporting requirement for Cyber Security Incidents is appropriate to carry out FPA section 215. As NERC recognizes in its NOPR comments, "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities[,] … would create a more extensive baseline understanding of the nature of cyber security threats and vulnerabilities[,] … [and] is consistent with recommendations in

NERC's 2017 State of Reliability Report."[4] Our directive is intended to result in a measured broadening of the existing reporting requirement in Reliability Standard CIP-008-5, consistent with NERC's recommendation, rather than a wholesale change in cyber incident reporting that supplants or otherwise chills voluntary reporting, as some commenters maintain. Indeed, as NERC contends, we believe that the new "baseline understanding, coupled with the additional context from voluntary reports received by the E-ISAC, [will] allow NERC and the E-ISAC to share that information broadly through the electric industry to better prepare entities to protect their critical infrastructure."[5]

5. We address in the discussion below concerns raised by commenters regarding elements of the Commission's directive and the burdens the directive might impose if NERC develops requirements that are overly broad. At the outset, we agree with NERC that "because certain requirements in the CIP Reliability Standards already require entities to track data on compromises or attempts to compromise the ESP or EACMS, the additional burden to report that data appears reasonable."[6] And we do not believe that complying with the augmented reporting requirements that we direct here would be any more burdensome to industry than the alternative, responding to a perpetual data or information request to collect the same information pursuant to Section 1600 of the NERC Rules of Procedure. To ensure that the burden is reasonable with respect to

[4] NERC Comments at 4.

[5] *Id.*

[6] *Id.* at 8 (citing Reliability Standard CIP-005-5 (Cyber Security — Electronic Security Perimeter(s)) and Reliability Standard CIP-007-6 (Cyber Security — System Security Management)).

including EACMS in the augmented reporting requirement, NERC should develop requirements based on the function of the EACMS and the nature of the attempted compromise or successful intrusion. Similarly, as discussed below, NERC should develop reporting timelines for Cyber Security Incidents that are commensurate with the adverse or attempted adverse impact to the BES that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES.[7] Prioritizing incident reporting will allow responsible entities to devote resources to reporting the most significant Cyber Security Incidents faster than less significant events. With this guidance, we believe that the standard drafting team, in the first instance, is in the best position to develop the specific elements of the directed Reliability Standard requirements.

6. We have considered comments submitted by NERC and others recommending that broadened Cyber Security Incident reporting should be implemented through a request for information or data pursuant to Section 1600 of the NERC Rules of Procedure instead of through Reliability Standard requirements. However, on balance, we believe that broadened mandatory reporting pursuant to Reliability Standard requirements as opposed to a standing data request is more aligned with the seriousness and magnitude of the

[7] The NERC Glossary defines BES Cyber System as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity." Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). Reliability Standard CIP-002-5.1a (Cyber Security System Categorization) provides a "tiered" approach to cybersecurity requirements, based on classifications of high, medium and low impact BES Cyber Systems.

current threat environment, and more likely to improve awareness of existing and future cyber security threats and potential vulnerabilities. Four main reasons inform our decision. First, a new or modified Reliability Standard will ensure that the desired goals of our directive are met because the Commission will have the ability to review and ultimately approve the standard, as opposed to the opportunity for informal review that the Commission would have of a data request under ROP Section 1600. Second, the Commission has well-defined authority and processes under section 215(e) of the FPA to audit and enforce compliance with a Reliability Standard. Third, we do not anticipate that there will be a need to change the parameters of the Cyber Security Incident report for EACMS because the parameters that we direct below are based on five static functions of EACMS and are not technology specific, so the potential flexibility provided by a Section 1600 data request may not be significantly beneficial. Finally, collecting data through a Reliability Standard is consistent with existing practices; responsible entities are currently required to maintain the types of information that would lead to a reportable Cyber Security Incident pursuant to Reliability Standard CIP-007-6, Requirement R4.1. Nonetheless, should future events require an expedited change in data collection or should NERC desire to collect data outside the scope of the proposed Reliability Standard, NERC could then use the Section 1600 process to supplement information reported under a mandatory Reliability Standard.

7. Accordingly, pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop modifications to the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt

to compromise, a responsible entity's ESP or associated EACMS, as well as modifications to specify the required information in Cyber Security Incident reports, their dissemination, and deadlines for filing reports. We direct NERC to submit the directed modifications within six-months of the effective date of this Final Rule.

I. Background

A. Section 215 and Mandatory Reliability Standards

8. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[8] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[9] and subsequently certified NERC.[10]

B. Notice of Proposed Rulemaking

9. On December 21, 2017, the Commission issued a NOPR proposing to direct that NERC develop enhanced Cyber Security Incident reporting requirements. Specifically, pursuant to section 215(d)(5) of the FPA, the NOPR proposed to direct NERC to develop

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[8] *Id.*

[9] *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).

[10] *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).

modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. The proposed directive was based in part on a lack of Reportable Cyber Security Incidents in 2015 and 2016, and NERC's assessment in the 2017 State of Reliability Report that "[w]hile there were no reportable cyber security incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low."[11] In addition, the NOPR stated that it agreed with the recommendation by NERC in the 2017 State of Reliability Report to "redefine reportable incidents to be more granular and include zero-consequence incidents that might be precursors to something more serious."[12]

10. In justifying the proposed inclusion of ESPs and associated EACMS within the scope of the enhanced Cyber Security Incident requirement, the NOPR stated that the purpose of an ESP is to manage electronic access to BES Cyber Systems to support the protection of the BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[13] In addition, the NOPR explained that EACMS, which include, for example, firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems, control electronic access into the ESP

[11] NOPR, 161 FERC ¶ 61,291 at P 28 (citing 2017 NERC State of Reliability Report at 4).

[12] *Id.* P 29 (citing 2017 NERC State of Reliability Report at 4).

[13] *See id.* P 33 (citing Reliability Standard CIP-005-5 (Cyber Security – Electronic Security Perimeter(s)).

and play a significant role in the protection of high and medium impact BES Cyber Systems.[14] The NOPR indicated further that, once an EACMS is compromised, an attacker could more easily enter the ESP and effectively control the BES Cyber System or Protected Cyber Asset.

11. The NOPR discussed the scope of the present Cyber Security Incident reporting requirement. The NOPR observed that Reliability Standard CIP-008-5, Requirement R1.2 currently requires that each responsible entity shall document one or more Cyber Security Incident Plan(s) with one or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident. And where a Cyber Security Incident is determined to qualify as a Reportable Cyber Security Incident, the NOPR explained that responsible entities are required to notify the E-ISAC with initial notification within one hour from the determination of a Reportable Cyber Security Incident. The NOPR stated, however, that the NERC Glossary defines a Reportable Cyber Security Incident as "[a] Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity." The NOPR indicated that the definition of Reportable Cyber Security Incident, insofar as it excludes unsuccessful attempts to compromise or disrupt a responsible entity's core activities, is thus more narrow than the definition of "cybersecurity incident" in FPA section 215(a)(8), which

[14] *See id.* (citing Reliability Standard CIP-002-5.1 (Cyber Security – BES Cyber System Categorization), Background at 6; Reliability Standard CIP-007-6 (Cyber Security – System Security Management), Background at 4).

encompasses "a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the bulk power system."[15]

12. The NOPR stated that altering the Cyber Security Incident reporting threshold to require reporting of attempts to compromise, instead of only successful compromises, is consistent with information already logged by registered entities pursuant to current monitoring requirements in the Reliability Standards. The NOPR explained that Reliability Standard CIP-007-6, Requirement R4.1, mandates logging of detected successful login attempts, detected failed access attempts, and failed login attempts, and the Guidelines and Technical Basis for Requirement R4.1 states that events should be logged even if access attempts were blocked or otherwise unsuccessful.[16]

13. In addition to modifying the reporting threshold, the NOPR proposed to direct NERC to modify the Reliability Standards to specify the required information in Cyber Security Incident reports to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information, as well as the deadlines for submitting a report. Specifically, the NOPR proposed that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack

[15] 16 U.S.C. 824o(a)(8).

[16] *See* Reliability Standard CIP-007-6 (Cyber Security – Systems Security Management), Requirement R4.1.

vector used to achieve or attempt to achieve the Cyber Security Incident; and (3) the level of intrusion achieved or attempted by the Cyber Security Incident. The NOPR explained that knowledge of these attributes regarding a specific Cyber Security Incident will improve awareness of cyber threats to BES reliability. The NOPR also noted that the proposed attributes are the same as attributes already used by DHS for its multi-sector reporting and summarized by DHS in an annual report.[17]

14. The NOPR also proposed to continue to require that Cyber Security Incident reports be sent to the E-ISAC instead of the Commission, but the NOPR proposed to require that such reports also be sent to ICS-CERT and that NERC file with the Commission an annual, public, and anonymized summary of such reports.

15. Finally, the NOPR sought comment on potential alternatives to modifying the mandatory reporting requirements in the NERC Reliability Standards. Specifically, the NOPR sought comment on whether a request for data or information pursuant to Section 1600 of the NERC Rules of Procedure would effectively address the reporting gap and current lack of awareness of cyber-related incidents among NERC, responsible entities and the Commission, and satisfy the goals of the proposed directive.

II. Discussion

16. Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit modifications to the NERC Reliability Standards to augment current mandatory reporting of Cyber Security Incidents, including incidents

[17] NOPR, 161 FERC ¶ 61,291 at P 38 (citing 2016 ICS-CERT Year in Review, https://ics-cert.us-cert.gov/Year-Review-2016).

that might facilitate subsequent efforts to harm the reliable operation of the BES. We direct NERC, subject to the discussion below, to develop and submit Reliability Standard requirements that: (1) require responsible entities to report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) specify the required information in Cyber Security Incident reports; (3) establish deadlines for filing Cyber Security Incident reports that are commensurate with incident severity; and (4) require that Cyber Security Incident reports be sent to ICS-CERT, in addition to E-ISAC, and that NERC file with the Commission an annual, public, and anonymized summary of such reports.

17. Below, we discuss the following matters: (A) the need for broadened mandatory Cyber Security Incident reporting; (B) the threshold for a reportable Cyber Security Incident; (C) the appropriate procedural approach to augment Cyber Security Incident reporting, i.e., new or modified Reliability Standards versus a NERC data request to applicable entities; (D) the content and timing of Cyber Security Incident reports; and (E) other issues.

A. Need for Broadened Mandatory Cyber Security Incident Reporting

1. NOPR

18. In the NOPR, the Commission indicated that cyber-related event reporting is currently addressed in Reliability Standard CIP-008-5, Requirement R1.2, which requires that each responsible entity shall document one or more Cyber Security Incident Plan(s) with one or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident. The NOPR noted that a Cyber Security Incident is

defined in the NERC Glossary as: "A malicious act or suspicious event that: (1) compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or (2) disrupts, or was an attempt to disrupt, the operation of a BES Cyber System."

19. The Commission further explained that where a cyber-related event is determined to qualify as a Reportable Cyber Security Incident**,** responsible entities are required to notify the E-ISAC with initial notification to be made within one hour from the determination of a Reportable Cyber Security Incident.[18] However, the NOPR observed that a Reportable Cyber Security Incident is defined more narrowly in the NERC Glossary than a Cyber Security Incident because the former requires that the incident result in the compromise or disruption of one or more reliability tasks of a functional entity. As the Commission explained, in order for a cyber-related event to be considered reportable under the existing CIP Reliability Standards, it must compromise or disrupt a core activity (e.g., reliability task) of a responsible entity that is intended to maintain BES reliability.[19] Therefore, under these definitions, unsuccessful attempts to compromise or

[18] *See* Reliability Standard CIP-008-5 (Cyber Security – Incident Reporting and Response Planning), Requirement R1, Part 1.2. This requirement pertains to high impact BES Cyber Systems and medium impact BES Cyber Systems.

[19] The NERC Functional 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. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions)." NERC, Reliability Functional Model: Function Definitions and Functional

disrupt a responsible entity's core activities are not subject to the current reporting requirements in Reliability Standard CIP-008-5 or elsewhere in the CIP Reliability Standards.

20. The NOPR explained that recent NERC State of Reliability Reports indicate that there were no Reportable Cyber Security Incidents in 2015 and 2016. The NOPR also highlighted NERC's conclusion that "[w]hile there were no reportable cyber security incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low."[20] The NOPR contrasted the results reported in the NERC reports with the 2016 annual summary of the Department of Energy's (DOE) Electric Disturbance Reporting Form OE-417, which contained four cybersecurity incidents reported in 2016; two suspected cyber attacks and two actual cyber attacks.[21] Moreover, the NOPR noted that ICS-CERT responded to fifty-nine cybersecurity incidents within the Energy Sector in 2016.[22]

21. Based on the comparison of information reported by NERC, DOE, and ICS-CERT, the NOPR concluded that the current reporting threshold in Reliability Standard

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Entities, Version 5 at 7 (November 2009), http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf.

[20] 2017 NERC State of Reliability Report at 4.

[21] 2016 DOE Electric Disturbance Events (OE-417) Annual Summary Archives, https://www.oe.netl.doe.gov/OE417_annual_summary.aspx.

[22] ICS-CERT cybersecurity incident statistics for the Energy Sector combine statistics from the electric subsector and the oil and natural gas subsector. ICS-CERT does not break out the cybersecurity incidents that only impact the electric subsector. 2016 ICS-CERT Year in Review, https://ics-cert.us-cert.gov/Year-Review-2016.

CIP-008-5 may not reflect the true scope and scale of cyber-related threats facing responsible entities. In particular, the NOPR raised a concern that the disparity in the reporting of cyber-related incidents under existing reporting requirements, in particular the lack of any incidents reported to NERC in 2015 and 2016, suggests a gap in the current reporting requirements. The NOPR highlighted the fact that this concern is echoed in the 2017 NERC State of Reliability Report, which includes a recommendation that NERC and industry should "redefine reportable incidents to be more granular and include zero-consequence incidents that might be precursors to something more serious."[23] Agreeing with NERC's recommendation in the 2017 State of Reliability report, the NOPR proposed to direct NERC to address the apparent gap in cyber incident reporting.

2. Comments

22. NERC supports improving the reporting of Cyber Security Incidents, stating that "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities."[24] NERC maintains that enhanced reporting "would create a more extensive baseline understanding of the nature of cyber security threats and vulnerabilities."[25] NERC notes that broadening the scope of Cyber Security Incident reporting "is consistent with recommendations in NERC's 2017 State

[23] 2017 NERC State of Reliability Report at 4.

[24] NERC Comments at 4.

[25] *Id.* at 4.

of Reliability Report."[26] While NERC recognizes the need for enhanced Cyber Security Incident reporting, as discussed in the following sections, NERC does not support all aspects of the NOPR, including requiring enhanced cyber incident reporting through a modified Reliability Standard.

23. BPA, ITC, IRC, NYPSC, and NRG also support the NOPR proposal to direct NERC to address the gap in reporting Cyber Security Incidents. As noted by BPA, the current definition of Reportable Cyber Security Incident only addresses successful attempts to compromise or disrupt operations and, therefore, "a broader definition of a Reportable Cyber Security incident is warranted" because "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[27] BPA, ITC, and IRC raise concerns, however, regarding the risk of over-reporting. IRC states that the proposed requirement to report all attempts to compromise an ESP or associated EACMS "needs further clarification."[28] BPA states that any new reporting requirement "must ensure that the information reported is useful and does not result in under and over reporting of information."[29] NRG recommends that the term "attempt" should be clarified (i.e., as a more serious risk than a port scan) and "should be

[26] *Id.* at 4.

[27] BPA Comments at 3.

[28] IRC Comments at 1.

[29] BPA Comments at 3.

provided in technical guidance or glossary definition relating to the context of [the] existing NERC glossary term: Cyber Security Incident."[30]

24. EEI/NRECA, Trade Associations, APS, Chamber, EnergySec, Eversource, Idaho Power, and LPPC do not support the NOPR proposal to direct NERC to address the gap in reporting Cyber Security Incidents. EEI/NRECA, Trade Associations, and Chamber suggest that the Commission support existing voluntary reporting practices as opposed to mandating the reporting of Cyber Security Incidents through the CIP Reliability Standards. EEI/NRECA state that "[s]ignificant resources from responsible entities and government are engaged in […] partnerships" to share threat and vulnerability information.[31] EEI/NRECA argue that "[m]andating such sharing will overlap with these voluntary efforts and may harm the partnerships and ability of the programs to enhance cybersecurity for the electric grid."[32] In addition, EEI/NRECA state that mandating Cyber Security Incident reporting "may weaken the ability of electric companies to participate in these [voluntary reporting] programs by shifting their focus to compliance activity."[33] Eversource states that the NOPR proposal would "introduce new technical and administrative challenges that will likely impact responsible entities' ability to

[30] NRG Comments at 3.

[31] EEI/NRECA Comments at 12.

[32] *Id.* at 12.

[33] *Id.* at 14-15.

participate in existing voluntary threat information sharing programs."[34] LPPC states that whatever action the Commission takes on Cyber Security Incident reporting, it "must be done with an eye towards causing as little disruption to existing information sharing programs as possible."[35]

25. Trade Associations state that while improving Cyber Security Incident reporting is an appropriate objective, "directing new or revised mandatory reliability standards is not the only tool that NERC and the Commission have for achieving that reliability objective."[36] Trade Associations contend that, in light of the constantly evolving state of cyber security, "the Commission should consider and utilize the most flexible tools to achieve its reliability goals without imposing undue burden on registered entities."[37]

26. APS states that while it "supports the Commission's objectives expressed in the NOPR," it does not agree that modifying the CIP Reliability Standards is the appropriate solution.[38] APS asserts that "the reporting requirements that already exist under Form OE-417 meet the same objectives as the Commission is attempting to satisfy by requiring additional reporting under the CIP Standards as proposed in the NOPR."[39] APS instead

[34] Eversource Comments at 5.

[35] LPPC Comments at 4.

[36] APPA, *et al.* Comments at 3-4.

[37] *Id.* at 4.

[38] APS Comments at 5.

[39] *Id.* at 7.

suggests that "the Commission … direct NERC to modify the CIP Standards to include a requirement for Responsible Entities to submit copies of its Form OE-417 to the E-ISAC and ICS-CERT."[40]

27. EnergySec states that it is "generally in agreement with the Commission's goal of increasing the frequency and detail of incident reporting," but raises concerns with the specifics of the NOPR proposal.[41] EnergySec maintains that "'compromise' as used in the definition of Reportable Cybersecurity Incident does not necessarily imply harm."[42] Therefore, EnergySec argues that "an incident should be considered a 'compromise' if an attacker has obtained the ability to disrupt, even if no disruption occurs."[43] EnergySec states further that it believes "that a clarified understanding of the current definition of Reportable Cybersecurity Incident can sufficiently address the Commission's concerns" since it "can be construed to include certain non-impactful incidents, as well as incidents affecting [ESPs] and [EACMS]."[44]

28. EnergySec also raises a concern that the NOPR proposal is too broad. EnergySec argues that determining incidents that might facilitate future cyber incidents "would be highly subjective and could easily be construed to include systems and networks that are

[40] *Id.* at 5.

[41] EnergySec Comments at 2.

[42] *Id.* at 2.

[43] *Id.* at 2.

[44] *Id.* at 3.

outside the scope of the Commission's authority."[45] EnergySec notes that most failed login or access attempts are benign in nature and "the volume of such events is orders of magnitude larger than what would be an appropriate volume for mandatory reporting."[46] EnergySec states further that while it agrees that successful attacks against ESPs and EACMS should be reported, it does not support including attempted compromise in the reporting requirements since the "[d]etermination of attempted compromise is highly subjective and it would therefore be difficult at best to clearly define within the standards a basis for such determinations."[47]

29. Eversource and Idaho Power do not support the NOPR proposal due to the anticipated increased burden that could result from increased mandatory reporting. Eversource states that "expanding the amount of required information to be reported and increasing the number of recipients of the reports will create undue administrative burdens."[48] In addition, Eversource contends that "the meaning of an attempted compromise is currently undefined and may impose significant burdens on responsible entities to identify such attempts."[49] Idaho Power states that even though "additional reporting can provide some visibility into the types of threats that entities face, additional

[45] *Id.* at 3.

[46] *Id.* at 3.

[47] *Id.* at 3-4.

[48] Eversource Comments at 1.

[49] *Id.* at 6.

administrative burdens such as reporting requirements reduce the finite resources that entities have to monitor and defend their critical infrastructure."[50]

30. LPPC asserts that the NOPR proposal "may yield a substantial quantity of unhelpful information and confusing analysis, while needlessly burdening Registered Entities."[51] LPPC states that it supports NERC's request for flexibility in addressing enhanced Cyber Security Incident reporting and concludes that "a technical conference may productively explore the nature and scope of the various programs that currently exist for information sharing regarding threats and the incremental value of any new requirements."[52] Resilient Societies states that "the modifications proposed to improve the reporting of cybersecurity incidents are unlikely to have any significant positive effect."[53] Specifically, Resilient Societies states that the proposed reporting parameters are not broad enough because "reporting of malware infection is not necessarily within thresholds set on other criteria, such as 'compromise,' 'breach,' 'impact,' or 'disruption.[54]'" Resilient Societies also suggests that the Commission convene a public technical conference.

[50] Idaho Power Comments at 2.

[51] LPPC Comments at 1.

[52] *Id.* at 5-6.

[53] Resilient Societies Comments at 12.

[54] *Id.* at 10.

3. Commission Determination

31. We adopt the NOPR proposal and, pursuant to section 215(d)(5) of the FPA, direct NERC to develop and submit modifications to the Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES. Comments submitted by NERC and others support our determination that enhanced reporting of Cyber Security Incidents will address an existing gap in Cyber Security Incident reporting and will provide useful information on existing and future cyber security risks, as well as provide entities with better visibility into malicious activity prior to an event occurring. As noted in NERC's comments, "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities."[55] Similarly, BPA agrees with the directive to include attempted compromises in an enhanced reporting regime, stating that "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[56] Moreover, while the record reflects differing views on whether broadened

[55] NERC Comments at 4.

[56] BPA Comments at 3.

Cyber Security Incident reporting should be mandatory or voluntary, there is general agreement that improved reporting is an appropriate objective.[57]

32. Some commenters contend that the directive to require mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS is vague and requires clarification. Recognizing this concern, NERC states that "[t]he challenge is to scope any additional mandatory reporting requirements in a manner that collects meaningful data about security risks without creating an unduly burdensome reporting requirement."[58] While we address the threshold for a broadened reporting requirement issue in the next section, as a general matter, we agree with NERC that the scope of any new reporting requirement should be tailored to provide better information on cyber security threats and vulnerabilities without imposing an undue burden on responsible entities. Indeed, the NOPR proposal was not intended to be prescriptive or overly broad, but rather support NERC's efforts to enhance the reporting of Cyber Security Incidents as outlined in NERC's 2017 State of Reliability Report through the standards development process.

33. Some commenters assert that a broadened reporting requirement will overlap, duplicate or otherwise chill voluntary reporting programs, potentially diverting resources away from such programs. Other commenters, however, assert that voluntary reporting

[57] *See* NERC Comments at 4, Trade Associations Comments at 3, APS Comments at 1, BPA Comments at 3, EnergySec Comments at 1, Idaho Power Comments at 2, ITC Comments at 5, IRC Comments at 1, NRG Comments at 2-3.

[58] NERC Comments at 3.

does not adequately address the gap identified in the NOPR because voluntary reporting and mandatory reporting under currently-effective Reliability Standard CIP-008-5 have not resulted in adequate reporting of cybersecurity threats to the BES.[59] As Appelbaum notes, "[w]ithout mandatory reporting scheme a degraded threat image will result."[60]

34. Based on the record, we are not persuaded that our directive to augment current mandatory reporting requirements will adversely impact existing voluntary information sharing efforts. Instead, we agree with NERC's comment that the new "baseline understanding [resulting from broadened mandatory reporting], coupled with the additional context from voluntary reports received by the E-ISAC, [will] allow NERC and the E-ISAC to share that information broadly through the electric industry to better prepare entities to protect their critical infrastructure."[61] Moreover, we do not anticipate that the incremental burden of the directed modifications will divert significant resources from other information sharing programs since responsible entities are already required to monitor and log successful login attempts, detected failed access attempts, and failed login attempts under Reliability Standard CIP-007-6, Requirement R4.1. Nor do we anticipate that the incremental burden of complying with the directed Reliability Standards modifications would be significantly more than the burden of responding to a standing data or information request under Section 1600. We also do not believe that broadened mandatory reporting is at cross-purposes with voluntary cybersecurity-related

[59] *See id.* at 4-5.

[60] Appelbaum Comments at 7.

[61] NERC Comments at 4.

programs offered by DHS and other government agencies. We believe that voluntary programs that focus on cyber response and sharing of cyber threat information across industry are important initiatives that should be supported. However, the comments do not provide a compelling explanation why the broadening of mandatory reporting will supplant or inhibit voluntary programs.

35. While we agree with EnergySec that revisions to the current definition of Reportable Cyber Security Incident could address some aspects of our directive, a modified definition alone would not address the need to specify the required information in Cyber Security Incident reports to improve the quality of reporting and allow for ease of comparison, or establish deadlines for submitting a report to facilitate timely information sharing. Therefore, while we believe that a modified definition of Reportable Cyber Security Incident could address part of the Commission's concerns, additional modifications would be necessary to meet the full scope of our directive.

36. In addition, we do not agree with Resilient Societies that the detection of malware infecting a responsible entity's ESP or associated EACMS would fall outside the new reporting requirement. While Resilient Societies asserts that a malware infection would not meet the threshold of a compromise, breach, impact, or disruption, we believe that it would fall within the parameters of an attempted compromise. As discussed in the next section, however, we believe that it is appropriate for NERC to address the reporting threshold through the standards development process in order to weigh the diverse technical opinions on how to identify the appropriate assets and the level of attempted compromise that warrants reporting. Accordingly, we are not persuaded to convene a

technical conference. Rather, persons interested in the development of appropriate detailed parameters of the augmented reporting requirements should participate in the NERC standards development process.

37. In sum, we conclude that the record supports our determination that directing NERC to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP, as well as associated EACMS, is appropriate to carry out FPA section 215. Therefore, pursuant to FPA section 215(d)(5), we direct NERC to develop and submit modifications to the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. As noted above, we direct NERC to submit the directed modifications within six-months of the effective date of this Final Rule.

B. Threshold for a Reportable Cyber Security Incident

1. NOPR

38. The NOPR proposed to direct NERC to modify the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. The NOPR explained that reporting attempts to compromise, instead of only successful compromises, is consistent with current monitoring requirements in Reliability Standard CIP-007-6, Requirement R4.1, which mandates logging of detected successful login attempts,

detected failed access attempts and failed login attempts.[62] In addition, the NOPR identified other reporting regimes that include attempts within the general definition of a "cyber incident." Specifically, DHS defines a "cyber incident" as "attempts (either failed or successful) to gain unauthorized access to a system or its data…."[63] The E-ISAC defines a "cyber incident" as including unauthorized access through the electronic perimeter as well as "a detected effort … without obvious success."[64] And ICS-CERT defines a "cyber incident" as an "occurrence that actually or potentially results in adverse consequences…."[65]

39. As noted above, an ESP is defined in the NERC Glossary as the "logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." The purpose of an ESP is to manage electronic access to BES Cyber Systems to support the protection of the BES Cyber Systems against compromise that could lead to misoperation or instability in the BES. The NOPR explained that since an ESP is intended to protect BES Cyber Systems, it is reasonable to establish the compromise of, or attempt to compromise, an ESP as the minimum reporting threshold.

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[62] *See* Reliability Standard CIP-007-6 (Cyber Security – Systems Security Management), Requirement R4.1.

[63] *See* United States Computer Emergency Readiness Team (US-CERT) Incident Definition: https://www.us-cert.gov/government-users/compliance-and-reporting/incident-definition.

[64] *See* E-ISAC Incident Reporting Fact Sheet document: http://www.nerc.com/files/Incident-Reporting.pdf.

[65] *See* ICS-CERT Published "Common Cyber Security Language" document: https://ics-cert.us-cert.gov/sites/default/files/documents/Common%20Cyber%20Language_S508C.pdf.

40. In addition, the NOPR identified an ESP's associated EACMS as another threshold for a Reportable Cyber Security Incident. As explained in the NOPR, EACMS are defined in the NERC Glossary as "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems." More specifically, EACMS include, for example, firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems.

41. While the Commission proposed to include EACMS within the scope of the proposed directive, the Commission also sought comment on the possibility of excluding EACMS from the scope of the proposed directive.

2. Comments

42. NERC supports the NOPR proposal to limit the scope of Cyber Security Incident reporting to incidents that compromise or attempt to compromise a responsible entity's ESP or associated EACMS. NERC explains that any new reporting requirements "need to be scoped in a manner that provides for meaningful reporting of cyber security risks but does not unduly burden entities."[66] Specifically, NERC states:

> Because the ESP protects some of the most important Cyber Assets and the EACMS control or monitor access to those Cyber Assets, NERC agrees that reporting on attempts to compromise these security measures would provide valuable data while also imposing a reasonable burden on entities given the limited traffic they should experience.[67]

[66] NERC Comments at 6.

[67] *Id.* at 7.

NERC notes that some EACMS devices "may provide important early indicators of future compromise" and, therefore, NERC states that it "supports including EACMS in the reporting threshold in addition to the ESP and notes that logging attempts to compromise the ESP and some EACMS devices does not impose an unreasonable burden on entities."[68]

43. While NERC supports adopting the compromise or attempt to compromise a responsible entity's ESP or an EACMS associated with an ESP as a threshold for Cyber Security Incident reporting, NERC explains that "there is still a need to refine the scope of the proposed directive to ensure that it would provide meaningful data without overburdening entities."[69] Specifically, NERC states that there is a need to "outline the parameters of an 'attempt to compromise' in order to issue a precise data request."[70] In particular, NERC states that it "would consider the common understanding of adverse activities that are early indicators of compromise, such as campaigns against industrial control systems, to help refine the parameters."[71] In addition, NERC notes that EACMS, as defined in the NERC Glossary, include a wide variety of devices that perform control and monitoring functions. NERC states further that it "needs to consider whether to define the reporting threshold to differentiate between the various types of EACMS for

[68] *Id.* at 8.

[69] *Id.* at 9.

[70] *Id.* at 9.

[71] *Id.* at 9.

reporting purposes."[72] Therefore, NERC requests that the Commission provide flexibility in refining the threshold for Cyber Security Incident reporting.

44. Trade Associations, APS, BPA, EnergySec, Resilient Societies, IRC, ITC, and NYPSC generally support the reporting threshold proposed in the NOPR, but caution that any new or modified requirements should be properly scoped. Trade Associations state that the NOPR proposal "is potentially overbroad and could result in unduly burdensome reporting requirements that *reduce* awareness of significant cyber threats."[73] Trade Associations also contend that a new or revised Reliability Standard "should not include the proposed generic threshold of reporting *any* incidents that compromise or attempt to compromise an ESP or EACMS."[74] Instead, Trade Associations recommend that the Commission "give NERC sufficient flexibility to define appropriate reporting thresholds for attempted compromises of an ESP or EACMS."[75]

45. APS asserts that, given the differences among EACMS, it does not support the inclusion of all EACMS or the exclusion of all EACMS from an enhanced reporting requirement. APS states that while it "concurs that the incidents impacting the ESP should certainly be in scope of reporting, it is concerned that the exclusion of EACMS (which includes [Electronic Access Points (EAP)]) results in a likely compromise

[72] *Id.* at 9.

[73] APPA, *et al*. Comments at 5 (emphasis in original).

[74] *Id.* (emphasis in original).

[75] *Id.* at 5.

scenario going unreported."[76] Specifically, APS notes that "a user's credentials to an Intermediate System, which includes/can be classified as an EAP(s) and/or EACMS, could be compromised."[77] APS contends that such a compromise would not implicate the ESP, but could impact or attempt to impact a BES Cyber Asset or System. APS states, however, that "there are numerous EACMS for which a compromise scenario would not be critical or allow potential access to an ESP."[78] Therefore, APS maintains that an evaluation of the functions of various EACMS is needed before they can be included in any reporting requirement.

46. BPA states that a broader definition of a Reportable Cyber Security Incident is necessary since the current definition only addresses actual compromises. BPA avers that "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[79] BPA states that the current definition of a Cyber Security Incident is a good starting point for a revision since it includes attempts to compromise or disrupt. BPA cautions, however, that the current definition of Cyber Security Incident "may be too broad and result in overreporting of information."[80]

[76] APS Comments at 9.

[77] *Id.*

[78] *Id.*

[79] BPA Comments at 3.

[80] *Id.* at 3.

47. EnergySec states that it "generally agree[s] that successful attacks against ESPs and EACMS should be within the scope of reporting; [but] disagree[s] with the proposal to include attempted compromise in the reporting requirements."[81] In addition, EnergySec suggests that monitoring-only systems be excluded from any reporting requirement, stating that "[a]lthough compromise of monitoring systems could assist an attack, such a compromise would not directly permit access."[82] Resilient Societies states that "[e]xcluding [EACMS] from the Commission directive could exempt reporting of attempted compromises."[83] IRC states that "adding EACMS to the requirement for mandatory reporting would be beneficial, not only because of their role as a boundary point, but also because EACMS perform other roles that support the BES Cyber Systems."[84] IRC cautions, however, that "[w]ithout providing further definitions or criteria, the NOPR's proposal to require reporting of all 'attempts to compromise' the ESP or EACMS is unclear and potentially unachievable."[85]

48. While ITC generally supports the NOPR proposal, ITC "requests that the Commission refrain from including unsuccessful attempts to compromise an ESP-

[81] EnergySec Comments at 3-4.

[82] *Id.* at 4.

[83] Resilient Societies Comments at 14.

[84] IRC Comments at 5.

[85] *Id.* at 3-4.

associated EACMS in the revised definition of a Cyber Security Incident."[86] ITC notes that responsible entity systems with publicly-visible IP addresses "sustain a regular stream of denial of service attempts, phishing emails, attempted firewall breaches, untargeted and targeted malware, and other common cybersecurity threats for which countermeasures are well-established and which pose a miniscule chance of success."[87] ITC states that including "attempted compromises of ESP-associated EACMS would appear to require reporting for a sizeable number of these common events."[88] Therefore, ITC states that while it "supports expanding the definition of Reportable Cyber Incidents to include incidents that compromise, or attempt to compromise, a responsible entity's ESP, ITC would urge the Commission to direct NERC to include only actual breaches of a responsible entity's ESP-associated EACMS, and not attempted-but-unsuccessful compromises."[89] NYPSC notes that "[f]ailed cyber attacks occur on a continuous basis, all the time…" and, therefore, "[a] reporting requirement of every attempted security attack may be overly burdensome for reporting entities."[90] NYPSC "suggests FERC

[86] ITC Comments at 5.

[87] *Id.* at 5.

[88] *Id.* at 5.

[89] *Id.* at 5.

[90] NYPSC Comments at 5-6.

consider developing clear criteria of the required reporting based on its review of the comments and recommendations from reporting entities."[91]

49. Idaho Power states that "additional reporting requirements do not increase cyber security."[92] Idaho Power contends that "additional administrative burdens such as reporting requirements reduce the finite resources that entities have to monitor and defend their critical infrastructure."[93] In addition, Idaho Power states that EACMS "should be excluded from any additional requirements and only BES Cyber Systems and associated devices should be included in any further reporting requirements."[94]

50. Other commenters support expanding the enhanced reporting requirement beyond what was proposed in the NOPR. NRG supports the NOPR proposal to direct NERC to develop modifications to the CIP Reliability Standards to improve the reporting of Cyber Security Incidents. NRG also supports including EACMS as a threshold for reporting. In addition, NRG "recommends that the scope of the NOPR avoid limiting the requirement to High and Medium Impact BES Cyber Systems."[95] Specifically, NRG notes that the NOPR proposal "would limit the requirement to High and Medium Impact BES Cyber Systems as ESPs and EACMS are not required establishments at Low Impact BES Cyber

[91] *Id.* at 6.

[92] Idaho Power Comments at 2.

[93] *Id.*

[94] *Id.*

[95] NRG Comments at 5.

Systems."[96] Therefore, NRG states that "any modification to the referenced CIP Reliability Standards should be applicable to all BES Cyber Systems with External Routable Communications."[97]

51. Appelbaum supports the NOPR proposal to include the attempted or actual compromise of an ESP or EACMS in the mandatory reporting requirement. However, Appelbaum "propose[s] the Commission consider adding Physical Security Perimeters and Physical Access Control Systems (PACS) as well."[98] Simon supports the NOPR proposal, but encourages the Commission to broaden the directive to include low impact BES Cyber Systems. Specifically, Simon states that "[o]mission of mandatory reporting for the disruption, or an attempt to disrupt, the operation of electronic access controls for BES assets with low impact BES Cyber Systems leaves a large blind spot in the Commission's effort to learn of efforts to harm the reliable operation of the bulk electric system."[99] Isologic does not support limiting Cyber Security Incident reporting to situations involving an entity's ESP or associated EACMS. Isologic states that "there are few CIP standards for 'secure perimeters' and for the mass of BES Low Impact Facilities, (substations), security is at the fence line, not in ESPs."[100]

[96] *Id.* at 2.

[97] *Id.*

[98] Appelbaum Comments at 7.

[99] Simon Comments at 4.

[100] Isologic Comments at 7.

3. Commission Determination

52. The record in this proceeding supports establishing the compromise or attempted compromise of an ESP as the appropriate threshold for a Reportable Cyber Security incident. In addition, with exceptions, the comments support including EACMS associated with an ESP as part of the reporting threshold. As NERC notes, an "ESP protects some of the most important Cyber Assets and the EACMS control or monitor access to those Cyber Assets."[101] While we believe that ESPs and EACMS should be within the scope of a broadened reporting requirement, the comments, correctly in our view, point to the need to establish an appropriate scope for reporting. As NERC states, "there is still a need to refine the scope of the proposed directive to ensure that it would provide meaningful data without overburdening entities."[102] This concern is reflected in a number of comments, pointing to the need to identify the appropriate assets to monitor (for example, only EACMS associated with an ESP) and to clearly define an "attempt to compromise."[103]

53. The comments generally support the view that NERC should have the flexibility to establish an appropriate reporting threshold. We recognize the need for a certain level of flexibility and believe that it is appropriate for NERC to address the specific reporting threshold through the standards development process. However, as discussed further

[101] NERC Comments at 7.

[102] *Id.* at 9.

[103] *See* NERC Comments at 9, APPA, *et al*. Comments at 5, APS Comments at 9, BPA Comments at 3, EnergySec Comments at 3, IRC Comments at 3-4, ITC Comments at 5, NYPSC Comments at 6.

below, we provide guidance on certain aspects of how NERC should identify EACMS for reporting purposes and what types of attempted compromise must be reported.

54. With regard to identifying EACMS for reporting purposes, NERC's reporting threshold should encompass the functions that various electronic access control and monitoring technologies provide. Those functions must include, at a minimum: (1) authentication; (2) monitoring and logging; (3) access control; (4) interactive remote access; and (5) alerting.[104] Reporting a malicious act or suspicious event that has compromised, or attempted to compromise, a responsible entity's EACMS that perform any of these five functions would meet the intended scope of the directive by improving awareness of existing and future cyber security threats and potential vulnerabilities. Since responsible entities are already required to monitor and log system activity under Reliability Standard CIP-007-6, the incremental burden of reporting of the compromise or attempted compromise of an EACMS that performs the identified functions should be limited, especially when compared to the benefit of the enhanced situational awareness that such reporting will provide.

55. With regard to the definition of "attempted compromise" for reporting purposes, we consider attempted compromise to include an unauthorized access attempt or other

[104] *See* NERC Glossary of Terms definition of EACMS. *See also* Reliability Standard CIP-006-6, Requirement R1.5 (Physical Security Plan) at 10 ("[i]ssue an alarm or alert in response to detected unauthorized access" to certain High and Medium Impact BES Cyber Systems and associated EACMS); Reliability Standard CIP-007-6, Requirement R4.2 (Security Event Monitoring) at 16; and Reliability Standard CIP-007-6, Requirement R5.7 (System Access Control) at 25.

confirmed suspicious activity. ITC raises a concern that including unsuccessful attempts to compromise an EACMS associated with an ESP would require reporting a significant number of events. We note, however, that limiting the reporting threshold to only EACMS that are associated with an ESP should limit the reporting burden since these assets should be located apart from the responsible entity's broader business IT networks. Moreover, as discussed in the next section, we also believe that a flexible reporting timeline that reflects the severity of a Cyber Security Incident could also help address the potential burden of reporting attempted compromises.

56. With regard to BPA's suggestion that a revised definition of Reportable Cyber Security Incident is necessary, as discussed above, revisions to the current definition of Reportable Cyber Security Incident could address certain aspects of the NOPR proposal, although a modified definition alone would not address the need to specify the required information in cyber security incident reports to improve the quality of reporting and allow for ease of comparison, or establish deadlines for submitting a report to facilitate timely information sharing. Therefore, although we believe that a modified definition of Reportable Cyber Security Incident could address part of the Commission's concerns, additional modifications to the Reliability Standards would be necessary to meet the security objective of the directives discussed herein.

57. A number of commenters request that we expand the directive to include a broader scope of assets, including low impact BES Cyber Systems. However, we decline to expand the scope of Cyber Security Incident reporting beyond the ESP and associated EACMS at this time. The focus on ESPs and associated EACMS is intended to provide

threat information on BES Cyber Systems that have the greatest impact on BES reliability while imposing a reasonable reporting burden on responsible entities. Nevertheless, the Commission could revisit this issue if there is demonstrated need for expanded Cyber Security Incident reporting.

58. Therefore, we adopt the NOPR proposal and conclude that the compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS is a reasonable threshold for augmented Cyber Security Incident reporting.

C. Appropriate Procedural Approach to Augment Cyber Security Incident Reporting

1. NOPR

59. The NOPR proposed to direct NERC to modify the CIP Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, while also seeking comment on whether a request for data or information pursuant to Section 1600 of the NERC Rules of Procedure would effectively address the reporting gap.

2. Comments

60. While NERC supports broadened mandatory Cyber Security Incident reporting, NERC does not support the NOPR proposal to direct a modification to the Reliability Standards. Instead, NERC requests flexibility to determine the appropriate reporting procedure. Specifically, NERC proposes to "use the [Rules of Procedure] Section 1600 process for gathering data used for system performance."[105] NERC maintains that it has

[105] NERC Comments at 10.

"successfully shifted to using Section 1600 for other data collection efforts, such as the collection of reports on Protection System Misoperation."[106] NERC explains further that the Section 1600 process would be used to "supplement the existing voluntary reporting of cyber security threats to E-ISAC."[107]

61. NERC states that the Section 1600 process "provides many of the same benefits as Reliability Standards," such as stakeholder and Commission staff input.[108] NERC also states that, similar to Reliability Standards, compliance with Section 1600 is mandatory. NERC explains that if a responsible entity does not respond to a Section 1600 data request, "NERC has the authority under the [Rules of Procedure] to take such action as NERC deems appropriate to address a situation where a Rule of Procedure cannot practically be complied with or has been violated."[109] NERC explains that the Section 1600 data request process provides the flexibility to revise or update the data request, if necessary, as well as "the flexibility to determine the appropriate timeline for submitting the data."[110] NERC states that while it may continue to use the Reliability Standards for data collection for evidence of compliance or to facilitate sharing of information between entities for BES operations, it "has found the [Rules of Procedure] Section 1600 process

[106] *Id.*

[107] *Id.*

[108] *Id.*

[109] *Id.* at 11.

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

to be effective for data collection to assess system performance."[111] NERC cites a standing Section 1600 data request for entities to submit quarterly data on Protection System Misoperations as an example.

62. LPPC supports the use of the Section 1600 process to facilitate enhanced Cyber Security Incident reporting. LPPC states that it "supports a more flexible approach to collection of actionable information through the data request process outlined in NERC ROP Section 1600."[112] LPPC asserts that the data request approach offers flexibility that the standards development process does not. Specifically, LPPC states that "compliance with a NERC data request is mandatory for applicable entities, while the data request procedures specified under [Rules of Procedure] Section 1600 also provide a more efficient process to update or revise a data request as needed to respond to rapidly-changing security threats."[113] Finally, LPPC opines that "it seems appropriate to remove the data collection process from the enforcement process associated with mandatory Reliability Standards."[114]

63. APS, BPA, Resilient Societies, IRC, and NRG oppose the use of the Section 1600 process to facilitate enhanced Cyber Security Incident reporting. APS asserts that a request for data pursuant to Section 1600 would not effectively address the reporting gap

[111] *Id.* at 12.

[112] LPPC Comments at 6-7.

[113] *Id.* at 7.

[114] *Id.*

and current lack of awareness of cyber-related incidents. Specifically, APS argues that a data request would create an independent, redundant reporting obligation to NERC or a regional entity and would subject the provisions of reported information to the confidentiality and data sharing processes set forth in Rules of Procedure Section 1500, unnecessarily delaying sharing and distribution of information.[115] APS states further that the Section 1600 process "adds significant additional administrative burden for all involved entities, which is inefficient and unnecessary and presents a potential obstacle to the very sharing and distribution that is a critical part of the Commission's objectives set forth in the NOPR."[116]

64. BPA comments that a data request is not an effective means of obtaining information about cyber security incidents. BPA explains that Section 1600 data requests "are one time requests for existing data, and […] not the appropriate vehicle for ensuring ongoing reporting necessary to make data about Cyber Security Incidents effective."[117] Resilient Societies states that "[e]xamination of NERC Rules of Procedure Section 1600 shows the intent of [the] rule is to facilitate one-time requests for data."[118] Therefore, Resilient Societies asserts that the Section 1600 reporting procedures "would be a poor fit for a standing order for data on cybersecurity incidents that occur continually."[119] NRG

[115] APS Comments at 16.

[116] *Id.* at 16-17.

[117] BPA Comments at 4.

[118] Resilient Societies Comments at 15.

[119] *Id.*

opposes the use of the Section 1600 data request process asserting that a request for data or information would neither address the current lack of awareness of cyber-related incidents, nor satisfy the goals of the proposed directive.

65. APS, as discussed above, suggests adopting the DOE Electric Disturbance Events, Form OE-417 as the primary reporting tool for Cyber Security Events. EnergySec, for its part, suggests that the Commission could direct NERC to require entities to develop and implement an information sharing plan.[120] According to EnergySec, such an approach should provide broad discretion to entities and ensure that compliance oversight efforts cannot result in second-guessing of decisions regarding which information to share, when, or with whom. IRC suggests, alternatively, that the Commission allow entities to comply with the reporting requirements by participating in the Cyber Risk Information Sharing program. IRC explains that the program allows entities to automatically report information to E-ISAC for analysis against classified information. IRC states that responsible entities that "automatically report indicators of compromise through these systems will share information at machine speed, and this should be considered superior to manual reporting, which requires much slower decision-making."[121]

3. Commission Determination

66. As discussed above, we adopt the NOPR proposal and direct NERC to develop modifications to the NERC Reliability Standards to improve mandatory reporting of

[120] EnergySec Comments at 6.

[121] IRC Comments at 7.

Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES. We have considered the arguments raised in the comments for using Reliability Standards, Section 1600 information and data requests, and other vehicles to implement augmented Cyber Security Incident reporting. On balance, we conclude that broadened mandatory reporting pursuant to Reliability Standard requirements is more aligned with the seriousness and magnitude of the current threat environment and the more effective approach to improve awareness of existing and future cyber security threats and potential vulnerabilities.

67. First, the development of a Reliability Standard provides the Commission with an opportunity to review and ultimately approve a new or modified Reliability Standard, ensuring that the desired goals of the directive are met. Moreover, the Reliability Standards development process allows for the collaboration of industry experts in developing a draft standard and also gives interested entities broader opportunity to participate and comment on any proposal that is developed. In contrast, NERC's process for developing a Section 1600 data request provides for less stakeholder input and only informal review of a draft data request by Commission staff. Thus, in this circumstance, the standards development process is preferable for the development of augmented cyber incident reporting requirements that satisfy the scope of the Commission's directive.

68. Second, the development of a Reliability Standard provides better assurance of accurate, complete, and verifiable reporting of cyber security incidents. The Commission has well-defined authority and processes under section 215(e) of the FPA to audit and enforce compliance with a Reliability Standard. While NERC notes that a responsible

entity must respond to a NERC Section 1600 data request, NERC cannot impose sanctions on registered entities who fail to respond to such data requests. Rather, a failure to comply would be a violation of the Commission's regulations,[122] requiring a referral to the Commission for action. Such a process would be a departure from the clearly defined processes used to enforce compliance with the Reliability Standards. Moreover, it is unclear how NERC would even learn of such a failure since, unlike mandatory Reliability Standards, compliance with Section 1600 data requests are not subject to regular audit. Accordingly, given the importance of accurate, complete, and verifiable cyber security incident reporting, we find that the more robust and well-established compliance and enforcement processes associated with mandatory Reliability Standards are desirable in this instance.

69. Third, we are not persuaded by NERC's assertion that a Section 1600 data request is preferable in this instance because it allows for flexibility and faster modification should a need arise for future revisions to the collection of cyber incident reporting data. We do not anticipate that there would be a need to change the parameters of the event report, given that the anticipated reporting requirements should not be technology-specific, but rather, broad enough to capture basic data even as the nature of cyber security incidents evolve. Specifically, the NOPR proposed that the minimum set of

[122] 18 CFR 39.2(b) (2017) ("All entities subject to the Commission's reliability jurisdiction…shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization and Regional Entity Rules made effective under this part.")

attributes to be reported should include: (1) the functional impact, where possible to determine, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident. Since these attributes are general in nature and not technology specific, they would not need to be refined as the underlying cyber threats evolve, nor would they need to be refined quickly.

70. In a similar vein, the assets (i.e., EACMS) subject to the enhanced reporting requirements should be identified based on function, as opposed to a specific technology that could require a modification in the reporting requirements should the underlying technology change. As discussed above, those functions must include, at a minimum: (1) authentication; (2) monitoring and logging; (3) access control; (4) interactive remote access; and (5) alerting. Finally, since the level of attempted compromise that warrants reporting should reflect unauthorized access attempts and other confirmed suspicious activity, we do not anticipate that a modification would be required in the future. Nevertheless, should the situation demand a more timely change in data collection or should NERC desire to collect additional information that is outside the scope of the proposed Reliability Standard, NERC could use the Section 1600 data request process to supplement information reported under a mandatory Reliability Standard.

71. Finally, requiring a data collection in a Reliability Standard is consistent with existing practices since responsible entities are currently required to maintain the types of

information that would lead to a reportable Cyber Security Incident pursuant to Reliability Standard CIP-007-6, Requirement R4.1.

72. While we recognize that NERC could likely develop a Section 1600 data request more quickly than a mandatory Reliability Standard, given the potential complexity of considering reporting requirements for the various EACMS, we believe that the technical depth of a standard development process is more appropriate for this case. Although NERC states that it has successfully used ROP Section 1600 to collect data on system performance, in this circumstance the information being reported relates to threats and potential compromises that may require immediate or near-term action as opposed to retrospective reporting on Misoperations, as Section 1600 has been used.

73. We also do not support adopting the DOE Form OE-417 as the primary reporting tool for reporting Cyber Security Incidents, as suggested by some commenters. The reporting criteria in our directive are distinguishable and more aligned with a risk management approach than the information requested in the DOE Form OE-417. Specifically, the DOE Form OE-417 has twelve generic criteria for filing a report to the DOE, of which only two reflect the criteria outlined in the NOPR proposal, which are discussed in the following section. The DOE Form OE-417 does not address factors such as attack vector, functional impact and level of intrusion. In addition, the definition of a "Cyber Event" in the DOE Form OE-417 filing instructions does not align with the definition of Cyber Security Incident in the NERC Glossary of Terms, let alone a

Reportable Cyber Security Incident.[123] Nor does the DOE Form OE-417 require reporting to E-ISAC or ICS-CERT as our directive requires.

74. In sum, we conclude that modifications to the NERC Reliability Standards to improve mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES, is the appropriate approach to improve Cyber Security Incident reporting.

D. Content and Timing of a Cyber Security Incident Report

1. NOPR

75. The NOPR proposed to direct that NERC modify the CIP Reliability Standards to specify the required content in a Cyber Security Incident report. Specifically, the NOPR proposed that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempt to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident. The NOPR noted that the proposed attributes are the same as attributes already used by DHS for its multi-sector reporting and summarized by DHS in an annual report. The NOPR stated that specifying the required content should improve the quality of reporting by ensuring that basic information is provided; and

[123] *See* Department of Energy Electric Emergency Incident and Disturbance Report – Form OE 417. Form OE-417 defines a Cyber Event as a disruption on the electrical system and/or communication system(s) caused by unauthorized access to computer software and communications systems or networks including hardware, software, and data. https://www.oe.netl.doe.gov/oe417.aspx

allowing for ease of comparison across reports by ensuring that each report includes specified fields of information. The NOPR sought comment on the proposed attributes and, more generally, the appropriate content for Cyber Security Incident reporting to improve awareness of existing and future cyber security threats and potential vulnerabilities.

76. In addition, the NOPR proposed to direct NERC to establish requirements outlining deadlines for filing a report once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity. The NOPR stated that the reporting timeline should reflect the actual or potential threat to reliability, with more serious incidents reported in a more timely fashion. The NOPR explained that a reporting timeline that takes into consideration the severity of a Cyber Security Incident should minimize potential burdens on responsible entities.

77. The NOPR also proposed that the reports submitted under the enhanced mandatory reporting requirements would be provided to E-ISAC, similar to the current reporting scheme under Reliability Standard CIP-008-5, as well as ICS-CERT or any successor organization. While the NOPR stated that the detailed incident report would not be submitted to the Commission, the NOPR proposed to direct NERC to file publicly an annual report reflecting the Cyber Security Incidents reported to NERC during the previous year. Specifically, the NOPR proposed to direct NERC to file annually an

anonymized report providing an aggregated summary of the reported information, similar to the ICS-CERT annual report.[124]

2. Comments

78. NERC supports the minimum set of reporting attributes proposed in the NOPR, stating that "this level of detail regarding each reported Cyber Security Incident will not only help NERC understand the specific threat but also help NERC understand trends in threats over time."[125] NERC also does not oppose either filing an annual, anonymized summary of the reports with the Commission, or submitting the reports of U.S.-based entities to the ICS-CERT in addition to E-ISAC. Finally, while NERC supports the concept of imposing a deadline for entities to submit full reports of Cyber Security Incidents, NERC requests flexibility to determine the appropriate timeframe. Specifically, NERC states that it "will determine an appropriate deadline for reports so that NERC can use the data for awareness and early indicators of potential compromise but also consider whether reporting for historical analysis can provide insight to the trends and effectiveness of industry's security controls."[126]

79. ITC, IRC, and NRG support the minimum set of reporting attributes proposed in the NOPR. ITC states that the NOPR proposal reflects "a reasonable set of baseline

[124] NOPR, 161 FERC ¶ 61,291 at 42.

[125] NERC Comments at 14.

[126] *Id.*

requirements for reporting."[127] While ITC raises a concern that the collective information in a report could potentially lead to the identification of the reporting entity, ITC states that it "will work within the NERC stakeholder and standards development process to ensure that the Standards submitted in response to the Commission's final rule are structured to preserve anonymity to the maximum extent practicable."[128] IRC asserts that "it will be beneficial for responsible entities to report indicators of compromise that are detected in potential cyberattacks against their systems in standard form."[129] NRG recommends that mandatory reporting include: "content Date, Time, Duration of Incident, Origination of the attack, threat vector, targeted system (or OS), vulnerability exploited, [and] method used to stop/prevent the attack."[130]

80. Appelbaum, APS, EnergySec, Resilient Societies, and Idaho Power raise concerns with the minimum set of reporting attributes proposed in the NOPR. According to Appelbaum, a count by category of asset, attack vector, and impact is sufficient for the mandatory reporting. APS contends that "because each entity's network topology, architecture, applications, and other characteristics are different, any requirement to

[127] ITC Comments at 6.

[128] *Id.*

[129] IRC Comments at 7.

[130] NRG Comments at 5.

provide the functional impact and level of intrusion as part of reporting is of very low value and should not be included as mandatory attributes of reporting."[131]

81. APS, however, "agrees that information regarding attack vectors could be more relevant, actionable information to be shared."[132] EnergySec expresses concern that including the proposed set of reporting attributes as a requirement could be construed to require significant forensic and analysis efforts. Resilient Societies suggests that the Commission leverage prior work done by the federal government as opposed to establishing new report content. Specifically, Resilient Societies suggests that the Commission adopt the US-CERT "Federal Incident Notification Guidelines." Idaho Power states that a "description of the event and the system(s) affected along with a fact pattern describing the situation and known information at the time the report is submitted should be sufficient."[133]

82. With regard to the timing of reports, ITC questions whether an initial report of a Cyber Security Incident would have to be submitted to ICS-CERT as well as E-ISAC. ITC opines that "the existing one-hour reporting requirement poses a significant compliance challenge, and that requiring that the initial report also be provided to ICS-CERT would be unworkable under that timeframe."[134] IRC states that "[t]he timeframe

[131] APS Comments at 11-12.

[132] *Id.* at 12.

[133] Idaho Power Comments at 3.

[134] ITC Comments at 7.

for completing a full report depends on the scale and scope of the investigation [and] FERC should consider requiring that reports be updated at a certain frequency until the full report is complete."[135] IRC recommends a 90-day update requirement until a report is finalized. NRG recommends that Cyber Security Incident reports should be submitted after existing industry processes have been followed relating to Incident Reporting and Response Plans. In addition, NRG recommends that the Commission consider directing NERC to file a quarterly report in addition to the annual report.

83. APS recommends aligning the timing of any mandatory reporting obligations with the timing dictated in Form OE-417. APS contends that reporting events that "could, but didn't, cause harm to the BES and/or facilitate subsequent efforts to harm … should be far enough removed from the incident to not divert resources from incident response and to ensure that enough details are known about the incident to provide an accurate, thorough report.[136]

84. EnergySec agrees that clear timelines should be included in any new mandatory Cyber Security Incident requirements. EnergySec further comments that the timelines should factor in the severity of the incident and the level of effort required to complete an investigation. Resilient Societies offers that "[i]n an ideal world, reporting of cybersecurity incidents would take place at machine speed" and suggests that the

[135] IRC Comments at 8.

[136] APS Comments at 13.

Commission "allow and preferably require automated reporting, at least for an initial report."[137] Idaho Power states that, should the Commission require timelines for reporting, it should ensure that an entity has adequate time to analyze each event before the reporting deadline.

85. Lasky supports entities being required to report Cyber Security Incidents to both E-ISAC and ICS-CERT, and states that "it would be prudent to report all incidents to the United States Cyber Emergency Response Team (US-CERT)" as well.[138]

3. Commission Determination

86. As discussed below, we adopt the NOPR proposal on minimum reporting attributes and timing, in response to the commenters' concerns, but we also leave discretion to NERC to develop the reporting timelines in the standards development process by considering several factors so that the timelines provide for notice based upon the severity of the event and the risk to BES reliability, with updates to follow initial reports.

87. The comments generally support the proposed minimum set of reporting attributes. For example, NERC supports the proposed content for a Cyber Security Incident report, while requesting flexibility to determine the appropriate reporting timeframe. As noted by ITC, the NOPR proposal reflects "a reasonable set of baseline

[137] Resilient Societies Comments at 15.

[138] Lasky Comments at 1.

requirements for reporting."[139] Certain comments do raise concerns with the proposed reporting attributes, especially in the case of attempts versus actual compromises.

88. In our view, a new or revised Cyber Security Incident report should include, at a minimum, the information outlined in the NOPR proposal, where available. Specifically, the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident. In addition, we agree that any reporting requirement should not take away from efforts to mitigate a potential compromise.

89. With regard to timing, we conclude that NERC should establish reporting timelines for when the responsible entity must submit Cyber Security Incident reports to the E-ISAC and ICS-CERT based on a risk impact assessment and incident prioritization approach to incident reporting.[140] This approach would establish reporting timelines that are commensurate with the adverse impact to the BES that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Higher risk incidents, such as detecting malware within the ESP and associated EACMS or an

[139] ITC Comments at 6.

[140] Similar to the Cyber Incident Severity Schema in DHS's National Cyber Incident Response Plan, Annex D (Reporting Incidents to the Federal Government) at 41 (2016), https://www.us-cert.gov/sites/default/files/ncirp/National_Cyber_Incident_Response_Plan.pdf.

incident that disrupted one or more reliability tasks, could trigger the report to be submitted to the E-ISAC and ICS-CERT within a more urgent timeframe, such as within one hour, similar to the current reporting deadline in Reliability Standard CIP-008-5.[141] For lower risk incidents, such as the detection of attempts at unauthorized access to the responsible entity's ESP or associated EACMS, an initial reporting timeframe between eight and twenty-four hours would provide an early indication of potential cyber attacks.[142] For situations where a responsible entity identifies other suspicious activity associated with an ESP or associated EACMS, a monthly report could, as NERC states, assist in the analysis of trends in activity over time.[143]

90. With regard to the appropriate recipients for Cyber Security Incident reports, we determine that the reports should be provided to E-ISAC, similar to the current reporting

[141] An example of incident categories is the Chairman of the Joint Chiefs of Staff Manual, Cyber Incident Handling Program, Enclosure B, Appendix A to Enclosure B (Cyber Incident and Reportable Cyber Event Categorization) (2012), http://www.jcs.mil/Portals/36/Documents/Library/Manuals/m651001.pdf?ver=2016-02-05-175710-897.

[142] *See* Department of Energy Electric Emergency Incident and Disturbance Report, Form OE-417 (six-hour reporting deadline for cyber events that could potentially impact electric power system reliability) found at: https://www.oe.netl.doe.gov/docs/OE417_Form_05312021.pdf; Nuclear Regulatory Commission Regulatory Guide 5.71 (four-hour reporting deadline for cyber events that could have caused an adverse impact) found at: https://www.nrc.gov/docs/ML0903/ML090340159.pdf; *see also* Reliability Standard EOP-004-3 (Event Reporting), Requirement R2 (requiring a report within twenty-four hours for an events that impact or may impact BES reliability).

[143] *See* NERC Comments at 14.

scheme under Reliability Standard CIP-008-5, as well as ICS-CERT or its successor.[144] Reporting directly to E-ISAC and ICS-CERT will result in cyber threat information being provided to the organizations best suited to analyze and, to the extent necessary, timely inform responsible entities of cyber threats. In addition, reporting directly to E-ISAC and ICS-CERT addresses the concerns discussed above regarding the confidentiality of reported Cyber Security Incident information. We also find that it is reasonable for NERC to file annually an anonymized report providing an aggregated summary of the reported information, similar to the ICS-CERT annual report. The annual report will provide the Commission, NERC, and the public a better understanding of any Cyber Security Incidents that occurred during the prior year without releasing information on specific responsible entities or Cyber Security Events.

91. Therefore, we conclude that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident. NERC may augment the list should it determine that additional information would benefit situational awareness of cyber threats. As discussed above, we also conclude that NERC should

[144] The DHS ICS-CERT is undergoing a reorganization and rebranding effort. In the event that ICS-CERT no longer exists, its successor will assume the role as incident report recipient.

establish a reporting timeline that provides for notice based upon the severity of the event and the risk to BES reliability, with updates to follow initial reports. We also support the adoption of an online reporting tool to streamline reporting and reduce burdens on responsible entities to the extent the option is available.[145]

E. Other Issues

1. Comments

92. NYPSC supports the NOPR proposal, but notes that if the Commission adopts the NOPR proposal, "the only additional information that state entities would gain is an annual compilation of incidents reported to federal entities."[146] NYPSC claims that an annual report would not provide states with sufficient information on a timely basis so that they can ensure that corrective actions can be taken. Therefore, NYPSC argues that appropriate state entities should also be provided with the cyber reporting information when it is filed with the "federal authorities."

93. Microsoft raises a concern that the NOPR proposal is not clear as to whether the modified CIP Reliability Standards would apply to responsible entities that use a commercial cloud service to operate cloud-based BES Cyber Systems. Specifically, Microsoft requests that the Commission "confirm that cloud service providers that

[145] An online reporting tool will streamline the effort and allow for direct input into a database for a faster turnaround to those that may need to know about the information. For example, *see* https://www.us-cert.gov/forms/report.

[146] NYPSC Comments at 4-5.

provide services to Registered Entities are not required to register with NERC based on their provision of [cloud-based] services, and … are not responsible for compliance with the CIP Reliability Standards."[147] Microsoft asserts that clarifying the status of cloud service providers is important to foster technical innovation.

2. Commission Determination

94. While we appreciate NYPSC's interest in receiving Cyber Security Incident reports when reported to E-ISAC and ICS-CERT, state entities will have access to the same information that is reported to the Commission (i.e., the annual, anonymized summary). Should a state entity determine that it requires additional information from a responsible entity under its jurisdiction, the state entity can work within its own jurisdiction to procure additional information. Our directive is intended to enhance the quality of information received by E-ISAC and ICS-CERT, and directing additional sharing with state entities is outside the scope of this proceeding.

95. We decline to grant Microsoft's requested clarification regarding the potential registration status of cloud service providers because it is outside the scope of this proceeding. Specifically, Microsoft's requested clarification addresses a question regarding registration of cloud service providers under the NERC functional model, as opposed to the specifics of enhanced Cyber Security Incident reporting. The purpose of this proceeding is not to make a determination regarding the registration status of cloud service providers and we have not received input from other interested entities.

[147] Microsoft Comments at 1.

III. Information Collection Statement

96. The FERC-725 information collection requirements contained in this Final Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[148] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[149] Upon approval of a collection 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. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

97. The Commission will submit these proposed reporting requirements to OMB for its review and approval under section 3507(d) of the PRA because the Final Rule results in nonsubstantive/non-material changes in paperwork burden. The Final Rule directs NERC to make Cyber Security reporting changes across all applicable Reliability Standards. These proposed changes will be covered by the FERC-725 information collection (Certification of Electric Reliability Organization; Procedures for Electric

[148] 44 U.S.C. 3507(d) (2012).

[149] 5 CFR 1320.11 (2017).

Reliability Standards) [OMB Control No. 1902-0225]). FERC-725 includes the ERO's overall responsibility for developing Reliability Standards to include any Reliability Standards that relate to Cyber Security Incident reporting. There will be no change to the Public Reporting Burden as it affects the FERC-725 information collection.

98. Comments are solicited on the Commission's need for the information proposed to be reported, whether the information will have practical utility, 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.

99. Internal review: The Commission has reviewed the approved changes and has determined that the changes are necessary to ensure the reliability and integrity of the Nation's Bulk-Power System.

100. 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].

101. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-8528, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to:

oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM18-2-000 and OMB Control Number 1902-0225.

IV. Regulatory Flexibility Act Analysis

102. The Regulatory Flexibility Act of 1980 (RFA)[150] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.

103. By only proposing to direct NERC, the Commission-certified ERO, to develop modified Reliability Standards for Cyber Security Incident reporting, this Final Rule will not have a significant or substantial impact on entities other than NERC. Therefore, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

104. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

V. Environmental Analysis

105. 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.[151] The Commission has categorically excluded certain

[150] 5 U.S.C. 601-612.

[151] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

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.[152] The actions proposed herein to augment current reporting requirements fall within this categorical exclusion in the Commission's regulations.

VI. Document Availability

106. 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.

107. 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. 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

[152] 18 CFR 380.4(a)(2)(ii) (2017).

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.

VII. Effective Date and Congressional Notification

108. The Final Rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined that this Final Rule imposes no substantial effect upon either NERC or NERC registered entities[153] and, 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. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[153] 5 U.S.C 804(3)c

Appendix
Commenters

Jonathan Appelbaum (Appelbaum)
American Public Power Association, Electricity Consumers Resource Council, and Transmission Access Policy Study Group (Trade Associations)
Applied Control Solutions (ACS)
Arizona Public Service Company (APS)
Bonneville Power Administration (BPA)
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Douglas E. Ellsworth (Ellsworth)
Energy Sector Security Consortium (EnergySec)
Eversource Energy Service Company (Eversource)
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)** **)**	**Docket No. RM13-11-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The North American Electric Reliability Corporation ("NERC") hereby submits this informational filing ("Informational Filing") to the Federal Energy Regulatory Commission ("Commission") as directed in Order No. 794.[1] In Order No. 794, the Commission approved Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) and directed NERC to submit an informational filing after implementation of the standard, "addressing: (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."[2] As discussed in this Informational Filing and detailed in the attached *Technical Report on NERC Standard BAL-003-1.1* ("Report"), the record demonstrates that: (1) the median method of calculating the Frequency Response Measure ("FRM") continues to provide more accurate results than the linear regression method; and (2) that sufficient frequency response resources existed in 2017 for applicable entities to meet their Frequency Response Obligation ("FRO").

In addition, data indicates that Reliability Standard BAL-003-1.1 has improved reliability by supporting recovery from frequency deviations. The Report summarizes lessons learned and

[1] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

[2] *Id.* at P 3. Prior filings in compliance with other directives in Order No. 794 have been submitted in the above captioned docket.

opportunities for enhancement being examined by the Standard Drafting Team ("SDT") developing modifications to Reliability Standard BAL-003-1.1 and by NERC technical committees. Together with industry, NERC will continue examining frequency response and potential modifications to Reliability Standards, as appropriate. NERC submits this Informational Filing in compliance with all remaining directives related to Order No. 794.

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this filing may be addressed to the following:[3]

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[3] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2018), to allow the inclusion of more than two persons on the service list in this proceeding.

II. COMMENTS

A. The Median Method of Calculating the FRM

In Order No. 794, the Commission stated that:

> [T]he Commission acknowledges NERC's commitment to studying the use of linear regression and the analysis contained in the Frequency Response Initiative Report, and directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission …. The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure.[4]

As detailed in the attached Report, data demonstrates that the median method of calculating the FRM continues to provide more accurate results than the linear regression method. To complete its statistical analysis, NERC compared the Interconnection Frequency Response Performance Measure ("IFRM") for each BAL-003-1.1 frequency event in the 2017 operating year,[5] against aggregate performance for all Balancing Authorities ("BAs") in the Interconnection for the same event as calculated under (1) the median method; and (2) the linear regression method. Under this statistical analysis, the method producing the outcome closest to 1.0 compared to the IFRM was considered to provide a better quality measurement.[6] NERC ran this comparison of the IFRM to aggregated BA FRMs as calculated under the median and linear regression methods for the Eastern, Western, and Texas Interconnections. For each Interconnection evaluated, the median method led to results closest to 1.0. Thus, NERC determined that the median method is the most accurate means of calculating the FRM under the current standard.

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[4] Order No. 794 at P 34.

[5] The first operating year that Requirement R1 was effective.

[6] The IFRM was used to benchmark accuracy of BA FRMs in this manner, because the IFRM is considered the most accurate calculation of frequency response performance in an Interconnection for any single BAL-003-1.1 frequency event as the IFRM does not include variables such as tie line error.

B. Adequacy of Frequency Response Resources in the First Year of Implementation of the Standard

In Order No. 794, the Commission:

> [D]irect[ed] NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation…. The required report should provide data indicating whether actual frequency response was sufficient to meet each balancing authority's Frequency Response Obligation.[7]

NERC has determined that adequate frequency response resources existed in 2017 for each BA to meet the FRO.[8] NERC reached this conclusion after evaluating the 2017 operating year results for Interconnections in the U.S. In the Texas Interconnection, the BA's FRM performance exceeded the FRO. For the Eastern and Western Interconnections, NERC evaluated BA frequency event data submitted for the 2017 operating year to assess whether a BA's percentage of total Interconnection generation was less than their percentage of the total IFRO. In the Western Interconnection, none of the 38 BA's FRM performance failed to meet the FRO.[9] In the Eastern Interconnection, 32 out of the 34 BAs had FRM performance satisfying the FRO. Only two BAs failed to have FRM performance meeting the FRO. These two BAs appear to have been outliers, however, as they were small BAs with combined FROs of less than 0.1% of the total IFRO of the Interconnection and did not use transferred frequency response to help meet their obligation. NERC will continue monitoring this issue.

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[7] Order No. 794 at P 60.

[8] Operating year 2017 was the first year of implementation for Requirement R1 of Reliability Standard BAL-003-1.1.

[9] Out of this group, 11 transferred frequency response from another BA during at least one event to support compliance with the standard.

C. The Report Summarizes Efforts to Further Address Issues Related to Frequency Response

As detailed in the Report, NERC is building on Reliability Standard BAL-003-1.1 to further address issues related to Frequency Response. The SDT for NERC Standards Project 2017-01 is evaluating potential modifications of NERC Reliability Standards in light of lessons learned under Reliability Standard BAL-003-1.1, the changing resource mix, inverter based resource penetration, altered dispatch patterns, and issues surrounding resource availability versus capability. Revisions to NERC Reliability Standards are being pursued over two phases to support continued progress towards enhanced reliability. Subject to completion of the standards development process and NERC Board of Trustees approval, NERC plans to submit the initial phase of modifications to Reliability Standard BAL-003-1.1 in 2019. In addition to SDT work, NERC will continue to coordinate with and rely on technical committee analysis of matters related to Frequency Response. The Resources Subcommittee of the Operating Committee, for example, has taken an active role over the past four years supporting NERC's implementation of the standard and its evaluation of frequency response matters.

III. CONCLUSION

Wherefore, as detailed in the Report, NERC's analysis demonstrates that: (1) the median method for calculating the FRM continues to provide more accurate results than the linear regression method; and 2) sufficient resources were available in operating year 2017 to support applicable entity FROs. NERC is continuing to build on the progress made in Reliability Standard BAL-003-1.1 through two phases of revisions to the standard and strong industry coordination. NERC submits this informational filing as compliant with the Commission's remaining directives in Order No. 794.

Respectfully submitted,

/s/ Candice Castaneda

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Counsel for the North American Electric Reliability Corporation

Date: June 29, 2018

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 29th day of June 2018.

/s/ Candice Castaneda

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Attachment

Technical Report on NERC Standard BAL-003-1.1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Report on NERC Standard BAL-003-1.1

Informational Filing in Compliance with FERC Order 794

June 29, 2018

RELIABILITY | ACCOUNTABILITY

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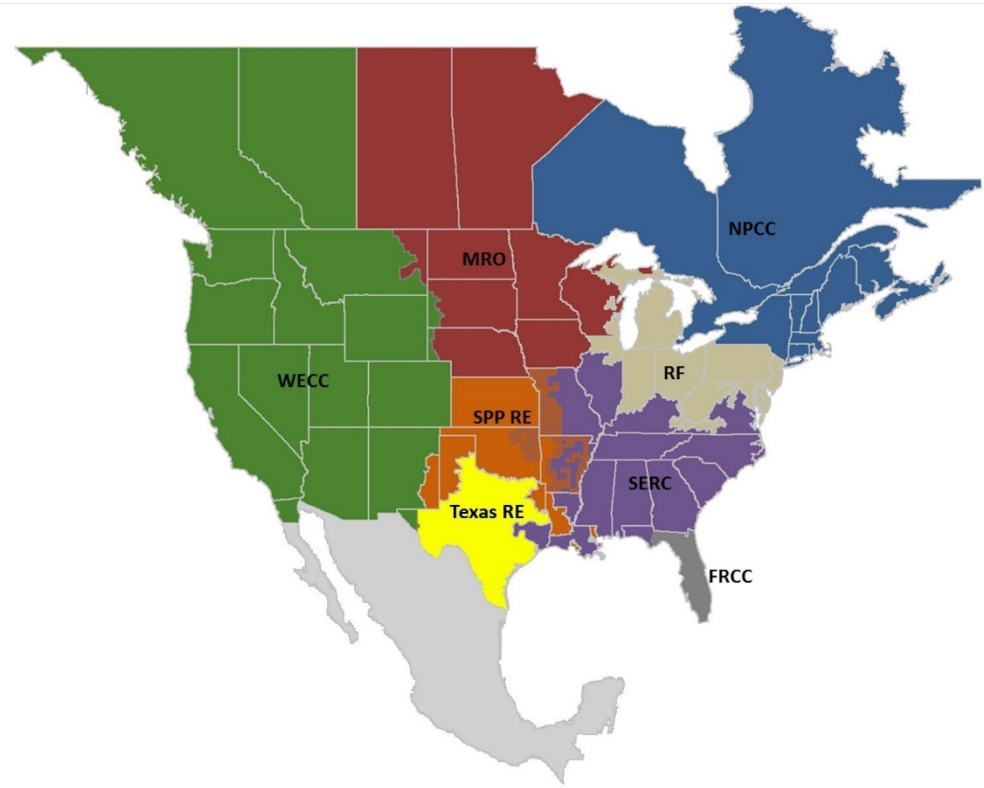
Table of Contents

Preface iii
Executive Summary iv
Response to Order No. 794 Directives iv
Introduction v
Chapter 1: Order 794 Directives 1
Analysis of Regression versus Median Statistical Method 1
Availability of Frequency Response Resources 2
Chapter 2: BAL-003-1.1 Standard Authorization Requests 4
Appendix A: Supporting Data 5

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into eight RE boundaries as shown in the map and corresponding table below. 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

In Order No. 794, the Federal Energy Regulatory Commission (FERC or Commission) approved *Reliability Standard BAL-003-1* and issued certain directives for an informational filing describing the results of implementation of the standard.[1] In the Order, the Commission directed NERC to do the following:

> "…submit a report(s) addressing: (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." [2]

NERC is submitting this report to satisfy those directives and prepared it by using frequency response performance data submitted by Balancing Authorities (BAs) in the Eastern Interconnection (EI), Western Interconnection (WI), and Texas Interconnection (TI) for the 2017 operating year[3] in accordance with BAL-003-1.1 Key findings and recommendations from the analysis described below are examined in this report and summarized in this executive summary.

Response to Order No. 794 Directives

The following are the findings and recommendations pertaining to directives of FERC Order No. 794:

1. **Evaluation of the Use of the Linear Regression Method to Calculate Frequency Response:** The median provided a better quality of measure of BA frequency response measure (FRM) performance as benchmarked against the Interconnection frequency response measure (IFRM) for events in the 2017 operating year. NERC recommends that Reliability Standard BAL-003-1.1 should continue to use the median method to measure annual BA FRM performance under the current construct of the standard.
2. **Evaluation of the Availability of Resources for Applicable Entities to Meet the Frequency Response Obligation:** NERC concludes that an adequate availability of frequency responsive resources existed in the 2017 operating year for each BA to meet their frequency response obligation (FRO).

This report also discusses work being done through Standards and Stakeholder Committee activities in support of Frequency Response.

[1] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶61,024 (2014).
[2] Order No. 794, p. 3.
[3] December 1, 2016 through November 30, 2017

Introduction

Frequency support is recognized as an essential reliability service. NERC *Reliability Standard BAL-003-1.1*[4] is intended to require sufficient frequency response from the BAs to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. Reliability Standard BAL-003-1.1 is intended to provide consistent methods for measuring frequency response and determining the frequency bias settings. The standard applies to all BAs or the FRSG, if the BA is a member of an FRSG.

NERC, in coordination with the REs, has established a target contingency protection criterion for each Interconnection called the IFRO. NERC manages the administrative procedure for annually assigning an FRO to each BA based on the allocation formula below that considers load and generation of the BA in relation to the Interconnection. All BAs in an Interconnection are allocated an FRO and are required to meet their obligation. This includes load-only and generation-only BAs regardless of size. In the event that a BA does not have resources within their footprint to meet their FRO, they may acquire frequency response from entities outside of their balancing area. This is also true of generation-only BAs when their resources may be off-line during BAL-003-1.1 frequency events. Load and generation data used to calculate FRO is sourced from the most recent FERC Form 714s filed by BAs, or from similar data requested by NERC when the BA is non-FERC jurisdictional.

$$FRO_{BA} = IFRO\ x\ \frac{Annual\ Gen_{BA} + Annual\ Load_{BA}}{Annual\ Gen_{Int} + Annual\ Load_{Int}}$$

Specifically, BAL-003-1.1 Requirement 1 reflects the connection between FROs and BA obligations and states:

> "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient frequency response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation."

Each BA calculates its FRM from single-event frequency response data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The ERO selects events in FRS Form 1 by using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.*[5] The FRS forms for each Interconnection are posted on the NERC Balancing Authority Submittal Site (BASS). The BASS is a secure website where BA users are vetted by NERC and granted access to obtain BAL-003-1.1 forms and information and to submit their annual performance results in accordance with the standard. NERC validates the submitted data that is also used to calculate annual frequency bias settings (FBS). The SEFRD for a typical BA in an Interconnection with more than one BA is basically the change in its net actual interchange on its tie lines with its adjacent BAs divided by the change in Interconnection frequency.[6] Assuming data entry is correct, FRS Form 1 is intended to automatically calculate the BA's FRM for the operating year as the median of the SEFRD values.

[4] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

[5] https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/Procedure_Clean_20121130.pdf

[6] Certain adjustments to the SEFRD calculation are allowed and are incorporated into the FRS Form 1 and 2 functionality. They include adjustments for Contingent BA, Non-Conforming Loads, Pumped Hydro, Dynamic Schedules, and Transferred Frequency Response between BAs. All events listed on FRS Form 1 must be included in the annual submission of FRS Forms 1 and 2.

Chapter 1: Order 794 Directives

Analysis of Regression versus Median Statistical Method

The Commission directed NERC to "assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure."[7] As stated in the Order:

> "… the Commission acknowledges NERC's commitment to studying the use of linear regression and the analysis contained in the Frequency Response Initiative Report, and directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure.[8]"

This report documents NERC's evaluation of the median versus regression method to determine BA FRMs based on the data collected following the implementation of BAL-003-1.1. Based on its analysis, NERC concludes that the median method provides a better quality of measure of BA FRM performance than linear regression. BAL-003-1.1 should continue to use the median to measure annual BA FRM performance under the current construct of the standard.

The median method provided a better quality of measure of BA FRM performance in the EI, WI, and TI as benchmarked against the IFRM for events in the 2017 operating year. BAL-003-1.1 should continue to utilize the median to measure annual BA FRM performance under the current construct of the standard.

The analysis herein uses BAL-003-1.1 frequency event data submitted by BAs in the EI and WI multi-BA Interconnections and the single-BA TI for the 2017 operating year. The 2017 operating year was the first year in which BAL-003-1.1 Requirement 1 was in effect for compliance purposes. BA performance data was submitted in years prior to the 2017 operating year under the BAL-003-1.1 field trial.

The premise of this analysis is that the calculation of frequency response performance at the interconnection level is the most accurate for any single BAL-003-1.1 event since it does not include variables, such as tie line error, metering error, and losses that may be seen at the BA level. The Interconnection frequency response performance measure ($IFRM_{A-B}$) calculates the ratio of the resource or load megawatt (MW) loss that initiated the event to the difference of predisturbance frequency (Value A) and the stabilizing period frequency (Value B). Value A and Value B are average frequencies from t_{-16} to t_{-2} and t_{+20} to t_{+52}, respectively, as defined in BAL-003-1.1. The MW loss experienced by the Interconnection that initiated the event must be determined in order to calculate $IFRM_{A-B}$ frequency response performance. Below is the equation for calculating $IFRM_{A-B}$.

$$IFRM_{A-B} = \frac{MW\ Loss}{10 * \Delta f_{A-B}}$$

Where:

MW Loss = Resource or Load Output immediately prior to the start of the event

f_{A-B} = Change in frequency from Value A to Value B

[7] Order No. 794, at P 34.

[8] *Id.*

This analysis compared the IFRM for each BAL-003-1.1 frequency event in the 2017 operating year to the aggregate performance for all BAs in the Interconnection for the same event. NERC analyzed BAL-003-1.1 events in EI, WI, and TI. The following reflects the analysis method:

- For analysis of the regression method the IFRM was plotted on the X-axis and the aggregated BA FRM performance is plotted on the Y-axis. The slope of the linear regression was calculated with the Y-intercept set to zero.
- For analysis of the median method the aggregated BA FRM performance was normalized for each event by dividing it by the IFRM for that event. The median of all aggregated BA FRM normalized events was then calculated.
- The results of the regression and median analyses are compared where the method that produces the outcome closest to 1.0 is considered to provide a better quality of measure as benchmarked against the IFRM.

The analyses of BAL-003-1.1 frequency events for the EI, WI, and TI produced consistent results as shown in **Table 1.1**. The median method produced the results closest to 1.0 for all three Interconnections using the aforementioned approach, suggesting that it produces a better quality of measurement than regression. The data that supports the aforementioned analysis and conclusion can be found in **Appendix A** of this report.

Table 1.1: Median versus Regression Analysis

Interconnection	Median	Regression	Preferred Method
Eastern	0.9784	0.9599	Median
Western	1.0138	1.0512	Median
Texas	0.9926	0.9895	Median

Conclusion

The median method provided a better quality of measure of BA FRM performance in the EI, WI, and TI as benchmarked against the IFRM for frequency events in the 2017 operating year. BAL-003-1.1 should continue to utilize the median to measure annual BA FRM performance under the current construct of the standard.

Availability of Frequency Response Resources

FERC Order No. 794 directed NERC to submit an evaluation of "the availability of resources for applicable entities to meet the Frequency Response Obligation."[9] The Commission "direct[ed] NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation."[10] Based on its analysis, NERC concludes that an adequate availability of frequency responsive resources existed in the 2017 operating year for each BA to meet their FROs.

Adequate frequency responsive resources were available during the first year of BAL-003-1.1 implementation for BAs to meet their FROs.

The analysis herein used BAL-003-1.1 frequency event data submitted by BAs for the 2017 operating year and BA FERC Form 714 load and generation data for the 2016 reporting year. The analysis focused on the 34 BAs in the EI and 38 BAs in the WI and evaluated the individual BA FRM compared to their FRO in 2017 under BAL-003-1.1. In addition, FERC Form 714 data was used to assess whether a BA's percentage of total Interconnection generation (MWh) was less than their percentage of the total IFRO. The FRM performance

[9] Order No. 794, at P 3.
[10] Order No. 794, at P 60.

of the single-BA TI exceeded its FRO throughout the 2017 operating year and as such was not pertinent to this analysis.

In the EI, there were only two BAs whose FRM performance did not meet their FRO. Both are small BAs with combined FROs of less than 0.1 percent of the total IFRO. Only one of these BAs had a percentage of interconnection generation that was less than their percentage of IFRO. Further, neither of these two BAs used the transfer of frequency response from other BAs in the Interconnection to meet their FRO. As a result, these two BAs appeared to be outliers, and their performance issue did not indicate an elevated reliability risk to the BPS or lack of available frequency response resources in their Interconnection. Fifteen of the 34 BAs in the EI had a smaller percentage of Interconnection generation than their percentage of IFRO as reported on FERC Form 714 for the 2016 reporting year. Of these 15 BAs, only one BA had an FRM performance that did not meet their FRO. None of the BAs in the EI used the transfer of frequency response for any events in the 2017 operating year.

In the WI, there were no BAs whose FRM performance did not meet their FRO. Twenty of the 38 BAs in the WI had a smaller percentage of Interconnection generation than their percentage of IFRO as reported on FERC Form 714s for the 2016 reporting year. Of these 20 BAs, none had an FRM performance that did not meet their FRO as previously noted. Eleven of the BAs in the WI used the transfer of frequency response for at least one event in the 2017 operating year. In the 2018 operating year the total WI FBS increased nearly 14 percent from the previous year. This is because increased frequency response performance for BAL-003-1.1 resulted in more BAs using a FBS between 100 percent and 125 percent of their previous operating year's FRM (in accordance with the standard) in lieu of a FBS based on the Interconnection minimum. The data that supports the aforementioned analysis and conclusion can be found in **Appendix A** of this report.

Conclusion

NERC concludes that adequate frequency responsive resources were available during the first year of BAL-003-1.1 implementation for all BAs to meet their FROs. This is also true for BAs whose percentage of Interconnection generation was less than their percentage of IFRO. The results of this analysis are only applicable for the historic 2017 operating year and may not be representative of future years where changes in the resource mix, increases in inverter-based resource penetration, and increasingly diverse dispatch patterns may occur. These issues, including the issue of availability versus capability are discussed further in this report.

Chapter 2: BAL-003-1.1 Standard Authorization Requests

NERC received two standards authorization requests (SARs) proposing modifications to *Reliability Standard BAL-003-1.1*. The first SAR[11] was submitted by the NERC Resources Subcommittee (RS) and was posted for industry comment from June 19, 2017, through July 18, 2017. The second SAR[12] was submitted by the Northwest FRSG and was posted for industry comment from November 2, 2017 through December 1, 2017. This SAR proposes a two-phase approach to modifying the current standard.

The recommendations detailed in this report provide technical support for the scope defined in the consolidated SAR.

In addition, several issues highlighted in these two SARs were anticipated and raised in more detail in the NERC *2016 Frequency Response Annual Analysis* (FRAA), which was accepted by the RS on August 25, 2016, and by the NERC Operating Committee on September 30, 2016, and filed with the Commission on October 21, 2016. The SARs and FRAA reflect better understanding of frequency response calculations (including calculation of IFRO) now that Reliability Standard BAL-003-1.1 has been implemented. Several of these lessons learned and findings are referenced above. Now that the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified in the standard and its supporting documents. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified.

Based on comments received from the postings, the NERC RS SAR and the Northwest FRSG SAR have been consolidated by the SAR drafting team to create a new SAR (the consolidated SAR). Phase I of the consolidated SAR proposes revisions to BAL-003-1.1 and process documents to address the following:

- The inconsistencies in calculation of IFROs due to Interconnection frequency response performance changes of Point C and/or Value B
- The Interconnection resource contingency protection criteria
- The frequency nadir point limitations (currently limited to t0 to t+12)
- Clarification of language in Attachment A (i.e., related to FRSG and the time line for frequency response and frequency bias setting activities)
- Enhancement of BAL-003-1 FRS Forms (including the ability to collect and submit FRSG performance data)
- Removal of administrative processes from Attachment A to an ERO approved reference document

The scope of the work identified in the second phase, Phase II of the Consolidated SAR, proposes that the standard drafting team (SDT) evaluate modifications to BAL-003-1.1 to do the following:

- Establish a real-time Reliability Standard addressing the necessary frequency response to maintain reliability.
- Establish comparability for the appropriate responsible entities.
- Develop real-time measurements incorporating topology difference.
- Eliminate the incorrect indicators.

The SDT is now pursuing the objectives laid out in the consolidated SAR.

[11] https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_SAR_June_2017.pdf
[12] https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_SAR_NWPP_Nov2017.pdf

Appendix A: Supporting Data

Regression versus Median Statistical Method Analysis—Eastern Interconnection

Table A.1: EI Statistical Method Analysis

EI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	Aggregated BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	Aggregated BA FRM Normalized by IFRM		
31-Dec-16	2,615	2,667	1.0199	MEDIAN	0.9784
10-Jan-17	2,819	2,322	0.8237	REGRESSION	0.9599
12-Jan-17	3,125	2,281	0.7299		
26-Jan-17	2,335	2,587	1.1077		
28-Jan-17	1,637	2,239	1.3677		
14-Feb-17	2,736	2,776	1.0145		
22-Feb-17	2,692	2,697	1.0019		
25-Feb-17	1,269	1,222	0.9634		
7-Mar-17	2,088	2,007	0.9615		
20-Mar-17	3,194	3,212	1.0056		
8-Apr-17	1,660	1,578	0.9506		
11-Apr-17	1,889	2,453	1.2987		
26-Apr-17	1,645	1,223	0.7434		
18-May-17	1,398	1,339	0.9576		
22-May-17	2,920	2,351	0.8053		
8-Jun-17	2,208	2,718	1.2310		
19-Jun-17	2,143	2,539	1.1849		
24-Jun-17	2,548	2,170	0.8518		
17-Jul-17	3,133	3,019	0.9635		
21-Jul-17	3,863	2,661	0.6890		
27-Aug-17	2,540	2,429	0.9562		
28-Aug-17	2,173	2,163	0.9951		
2-Sep-17	2,317	2,365	1.0208		
8-Oct-17	1,369	2,344	1.7124		
26-Oct-17	1,683	1,456	0.8648		
7-Nov-17	1,625	1,222	0.7517		
7-Nov-17	2,286	2,236	0.9784		
8-Nov-17	2,473	2,794	1.1301		
20-Nov-17	1,813	2,128	1.1739		

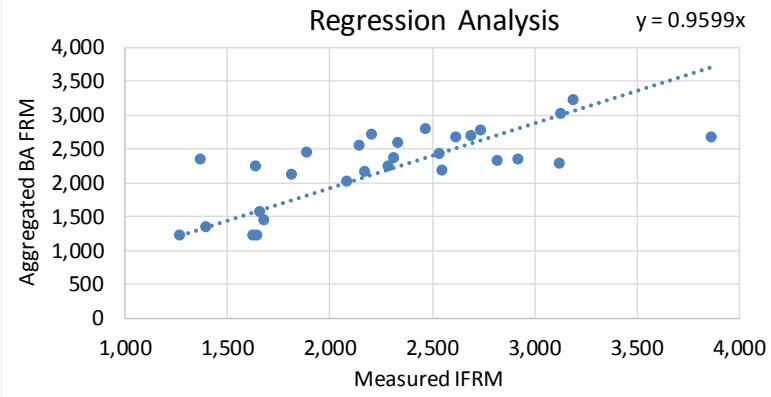


Figure A.1: EI Regression Analysis

Regression versus Median Statistical Method Analysis—Western Interconnection

Table A.2: WI Statistical Method Analysis

WI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	Aggregated BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	Aggregated BA FRM Normalized by IFRM		
19-Jan-17	2,536	1,532	0.60	MEDIAN	1.0138
20-Jan-17	1,838	1,670	0.91	REGRESSION	1.0512
24-Jan-17	2,676	2,932	1.10		
6-Feb-17	1,567	1,769	1.13		
6-Feb-17	1,382	1,371	0.99		
4-Mar-17	2,904	2,235	0.77		
8-Mar-17	1,722	1,947	1.13		
9-Mar-17	1,384	1,602	1.16		
17-Mar-17	1,691	1,420	0.84		
7-Apr-17	1,703	1,667	0.98		
14-Apr-17	1,250	1,234	0.99		
8-Jun-17	3,064	2,727	0.89		
15-Jun-17	1,215	1,170	0.96		
16-Jun-17	2,165	2,181	1.01		
19-Jun-17	1,728	2,385	1.38		
23-Jun-17	2,219	2,707	1.22		
4-Jul-17	1,358	1,540	1.13		
15-Jul-17	1,539	1,560	1.01		
29-Jul-17	2,158	2,233	1.03		
30-Jul-17	1,868	1,820	0.97		
8-Aug-17	1,527	1,763	1.15		
10-Sep-17	2,175	2,072	0.95		
15-Sep-17	2,286	3,033	1.33		
20-Sep-17	6,645	7,650	1.15		
24-Nov-17	1,709	2,082	1.22		

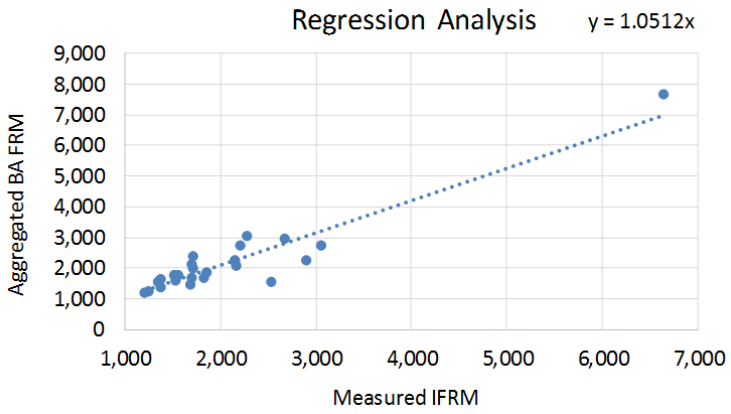


Figure A.2: WI Regression Analysis

Regression versus Median Statistical Method Analysis—Texas Interconnection

Table A.3: TI Statistical Method Analysis

TI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	BAL-003 BA FRM Normalized by IFRM		
23-Dec-16	570	566	0.9931	MEDIAN	0.9926
7-Jan-17	840	843	1.0038	REGRESSION	0.9895
24-Jan-17	2,041	2,016	0.9877		
14-Feb-17	520	519	0.9981		
20-Feb-17	780	774	0.9926		
10-Mar-17	823	820	0.9965		
15-Mar-17	670	673	1.0045		
30-Mar-17	909	908	0.9991		
10-Apr-17	731	585	0.7999		
13-Apr-17	514	504	0.9811		
16-Apr-17	491	496	1.0095		
26-Apr-17	1,123	1,135	1.0109		
11-May-17	732	711	0.9709		
19-May-17	919	898	0.9779		
21-May-17	700	697	0.9961		
2-Jun-17	727	736	1.0115		
6-Jun-17	611	604	0.9895		
7-Jun-17	1,124	1,110	0.9880		
11-Jun-17	671	659	0.9816		
12-Jun-17	750	751	1.0008		
16-Jun-17	1,447	1,426	0.9853		
27-Jun-17	792	798	1.0074		
2-Jul-17	773	782	1.0113		
26-Jul-17	702	693	0.9868		
9-Aug-17	631	615	0.9752		
23-Aug-17	797	799	1.0019		
1-Sep-17	1,037	1,013	0.9762		
2-Sep-17	1,450	1,438	0.9917		
9-Sep-17	1,221	1,194	0.9781		
6-Oct-17	839	845	1.0066		
8-Oct-17	1,116	1,123	1.0059		
30-Oct-17	684	685	1.0009		
6-Nov-17	764	759	0.9936		
13-Nov-17	687	682	0.9921		
18-Nov-17	641	636	0.9923		
26-Nov-17	991	996	1.0049		

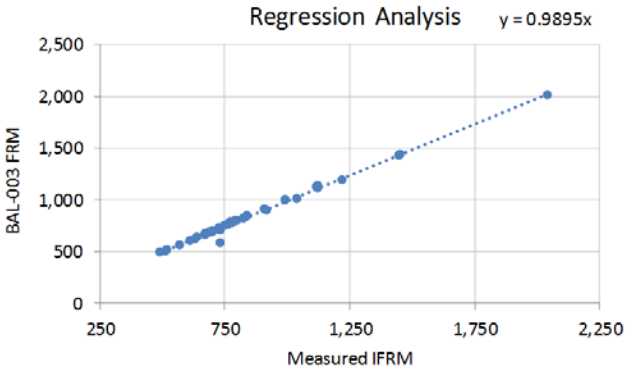


Figure A.3: TI Regression Analysis

Availability of Frequency Response Resources

BAs whose percentage of Interconnection generation was less than their percentage of IFRO as reflected on the FERC Form 714 submittals for the 2016 reporting year, are highlighted in red. See **Table A.4** and **Table A.5**.

Table A.4: EI Availability Analysis

2017 OY		Total $Gen_{BA}/TotalGen_{Int}$ Source: 2016 FERC 715
	FRM/FRO	% Int Generation - %IFRO
EI BA1	156%	-0.212%
EI BA2	230%	-0.007%
EI BA3	486%	0.090%
EI BA4	284%	-0.007%
EI BA5	-113%	-0.010%
EI BA6	406%	-0.019%
EI BA7	1105%	-0.010%
EI BA8	180%	0.169%
EI BA9	147%	-0.004%
EI BA10	125%	0.020%
EI BA11	546%	-0.642%
EI BA12	221%	0.181%
EI BA13	355%	-0.003%
EI BA14	290%	-0.315%
EI BA15	254%	-0.347%
EI BA16	297%	0.002%
EI BA17	217%	-0.006%
EI BA18	179%	0.255%
EI BA19	517%	0.158%
EI BA20	145%	0.291%
EI BA21	116%	0.014%
EI BA22	184%	0.032%
EI BA23	2296%	0.041%
EI BA24	168%	0.034%
EI BA25	265%	0.053%
EI BA26	412%	0.038%
EI BA27	142%	-0.012%
EI BA28	290%	0.040%
EI BA29	301%	-0.102%
EI BA30	-102%	0.030%
EI BA31	137%	0.154%
EI BA32	248%	-0.015%
EI BA33	500%	0.092%
EI BA34	170%	0%

Table A.5: WI Availability Analysis		
2017 OY		Total $Gen_{BA}/TotalGen_{Int}$ Source: 2016 FERC 715
	FRM/FRO	% Int Generation - % IFRO
WI BA1	317%	0.089%
WI BA2	192%	0.004%
WI BA3	307%	-0.058%
WI BA4	403%	-0.223%
WI BA5	257%	3.362%
WI BA6	161%	-3.461%
WI BA7	100%	-0.074%
WI BA8	202%	-0.262%
WI BA9	249%	0.102%
WI BA10	497%	0.414%
WI BA11	246%	0.036%
WI BA12	133%	-0.077%
WI BA13	103%	-0.121%
WI BA14	333%	-0.239%
WI BA15	100%	0.033%
WI BA16	270%	0.042%
WI BA17	235%	-0.297%
WI BA18	176%	0.197%
WI BA19	210%	0.003%
WI BA20	276%	-0.003%
WI BA21	189%	-0.086%
WI BA22	255%	-0.391%
WI BA23	120%	-0.244%
WI BA24	236%	0.037%
WI BA25	132%	0.254%
WI BA26	193%	0.234%
WI BA27	397%	0.053%
WI BA28	144%	-0.462%
WI BA29	287%	-0.070%
WI BA30	280%	-0.132%
WI BA31	280%	-0.007%
WI BA32	181%	-0.062%
WI BA33	283%	-0.040%
WI BA34	307%	0.840%
WI BA35	333%	-0.017%
WI BA36	156%	0.160%
WI BA37	213%	0.421%
WI BA38	220%	0.020%

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM18-8-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULE MAKING

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July 23, 2018

TABLE OF CONTENTS

I. BACKGROUND 3
II. COMMENTS 5
A. Corrective Action Plans for Supplemental GMD Vulnerability Assessments 6
1. NOPR 6
2. Comments 7
B. Extending Corrective Action Plan Deadlines 18
1. NOPR 18
2. Comments 20
III. Conclusion 23

UNITED STATES OF AMERICA
BEFORE THE
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North American Electric Reliability Corporation	**)** **)**	**Docket No. RM18-8-000**

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 Notice of Proposed Rulemaking ("NOPR") regarding proposed Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in this proceeding on May 17, 2018.[1] NERC provides these comments as the Commission-certified electric reliability organization responsible for the development and enforcement of mandatory Reliability Standards, including proposed Reliability Standard TPL-007-2.[2]

In the NOPR, the Commission proposes to approve proposed Reliability Standard TPL-007-2, as well as the associated implementation plan, Violation Risk Factors, and Violation Severity Levels. The Commission, however, proposes to direct NERC to revise the standard to require entities to develop Corrective Action Plans to address vulnerabilities identified through supplemental Geomagnetic Disturbance ("GMD") Vulnerability Assessments. In addition, the

[1] Notice of Proposed Rulemaking, *Geomagnetic Disturbance Reliability Standard*, 163 FERC ¶ 61,126 (2018) ("NOPR").

[2] The Commission certified NERC as the electric reliability organization ("ERO") in 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007), *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

Commission sets forth two possible proposals regarding proposed TPL-007-2 Requirement R7 Part 7.4, which relates to the circumstances under which an entity may extend Corrective Action Plan deadlines.

NERC supports the Commission's proposal to approve Reliability Standard TPL-007-2. The proposed standard raises the bar for reliability. It provides a flexible process for maintaining timeliness and accountability in the development and completion of Corrective Action Plans to mitigate identified GMD vulnerabilities. Further, the proposed standard addresses the Commission's directives from Order No. 830[3] to account for the localized peak effects of GMDs in planning studies.

As discussed in its Petition,[4] NERC's approach to accounting for localized peak effects of GMD is sound and reasonable based on currently-available information. Research is currently underway under NERC's GMD Research Work Plan to improve understanding of the characteristics and spatial scales of localized peak GMD effects.[5] To ensure that NERC's GMD Reliability Standard continues to reflect the best available information, NERC commits to initiate a review of TPL-007-2 following the completion of the work plan. As the research work described in NERC's GMD Research Work Plan is directly relevant to the standard modification proposals discussed in the NOPR, NERC encourages the Commission to allow NERC to complete this work and its subsequent review prior to issuing any further standard modification directives.

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3 *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215 (2016), *reh'g denied*, 158 FERC ¶ 61,041 (2017) ("Order No. 830").

4 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard TPL-007-2*, Docket No. RM18-8-000 (filed Jan. 22, 2018) ("Petition").

5 *See Revised Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation*, Docket No. RM15-11-003 (filed Apr. 19, 2018) ("GMD Research Work Plan").

For these reasons, which are explained more fully herein, NERC respectfully requests that the Commission approve Reliability Standard TPL-007-2 as proposed by NERC.

I. BACKGROUND

On January 22, 2018, NERC filed proposed Reliability Standard TPL-007-2 for Commission approval. The proposed standard was developed in response to the Commission's directives from Order No. 830, in which the Commission approved currently-effective Reliability Standard TPL-007-1. As explained in further detail in NERC's Petition, the proposed standard improves upon the currently-effective version of the standard and addresses the Commission's directives from Order No. 830 by:

- requiring entities to assess their vulnerabilities to the supplemental GMD event, a second defined event that accounts for the localized peak effects of severe GMD events and which is not based solely on spatially-averaged data;[6]
- requiring entities to perform supplemental thermal impact assessments of applicable power transformers based on geomagnetically-induced current ("GIC") information for the supplemental GMD event;[7]
- requiring entities to implement process(es) to obtain GIC monitor and magnetometer data;[8] and
- requiring entities to meet requirements for timeliness and accountability in implementing

[6] *See* Order No. 830 at P 44 ("[T]he Commission . . . 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.") and P 47 ("Without pre-judging how NERC proposes to address the Commission's directive, NERC's response . . . 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.").

[7] *See id.* at P 65 ("[T]he 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.").

[8] *See id.* at P 88 (directing NERC to modify TPL-007-1 "to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness"). Additionally, the Commission directed NERC to collect GIC monitoring and magnetometer data from entities for the period beginning May 2013 going forward, and to make that information available. *Id.* at P 89.

Corrective Action Plans for addressing identified benchmark GMD vulnerabilities.[9]

Like its predecessor version TPL-007-1, the proposed standard is based on the latest in scientific and technical understanding of severe GMD events and the potential risks these events may pose to reliability.

Since completing development of the proposed standard, NERC has continued its work on GMD issues. On April 19, 2018, NERC filed a revised GMD Research Work Plan with the Commission.[10] This plan provides a detailed framework for researching the specific GMD areas of concern noted by the Commission in Order No. 830. Later this year, NERC anticipates issuing a request to registered entities for GMD monitoring data under its authority in Section 1600 of the NERC Rules of Procedure.[11] These projects are expected to increase understanding of GMDs and provide useful information for continued evaluation of the technical aspects underpinning the proposed standard. To take advantage of these insights, NERC will initiate a formal review of the proposed TPL-007-2 standard following the conclusion of the GMD Research Work Plan. The purpose of this review will be to ensure that the GMD planning standard and the underlying GMD planning events are supported by the latest in scientific and technical understanding, identify any adjustments or refinements that may be necessary, and account for any other considerations that arise during the course of implementing the TPL-007 standard.

On May 17, 2018, the Commission issued a NOPR proposing to approve Reliability Standard TPL-007-2. In the NOPR, the Commission also proposes to direct NERC to modify the

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[9] *See id.* at PP 101-102 (directing NERC to modify TPL-007-1 to include a one-year deadline for the development of any required Corrective Action Plans, a two-year deadline to complete the implementation of non-hardware mitigation, and a four-year deadline to complete the implementation of hardware mitigation).

[10] GMD Research Work Plan, *supra* note 5.

[11] The NERC Rules of Procedure ("NERC ROP") are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

standard's requirements for Corrective Action Plans. Specifically, the Commission proposes to direct NERC to modify the standard "to require applicable entities to develop and implement corrective action plans to mitigate supplemental GMD event vulnerabilities."[12] With respect to proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.4, which relates to extension of Corrective Action Plan deadlines, the Commission proposes adopting one of two possible proposals. Under the first option, the Commission proposes to direct NERC to modify the standard to require "NERC and the Regional Entities, as appropriate, consider requests for extension of time [to complete Corrective Action Plan activities] on a case-by-case basis."[13] NERC would also be directed to prepare and submit a report regarding the circumstances under which such requests have been made and NERC's disposition of such requests. Under the second option, the Commission would approve TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC and would direct NERC to submit a report on the use of the provision.[14] The Commission seeks comments on its proposals.

II. COMMENTS

NERC supports the Commission's proposal to approve Reliability Standard TPL-007-2. Proposed Reliability Standard TPL-007-2 addresses the Commission's directives as set forth in Order No. 830 and represents another milestone in NERC's efforts to harden the grid against the potential reliability risks posed by severe GMD events, including the risks posed by severe,

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12 NOPR at P 24.

13 *Id*. at P 50.

14 *Id*. at P 51.

localized effects. NERC does not, however, support the Commission's proposals to further modify the standard.

As discussed below, the proposed standard provides strong protections against the potential reliability risks of a severe GMD event and provides a reasonable approach for mitigating vulnerabilities identified through the benchmark and supplemental GMD Vulnerability Assessments. NERC, therefore, does not support the Commission's first standard modification proposal, which is to direct NERC to modify the standard to require entities to develop Corrective Action Plans to address vulnerabilities identified through supplemental GMD Vulnerability Assessments. With respect to the second set of proposals regarding TPL-007-2 Requirement R7 Part 7.4, NERC supports the second option described by the Commission, which would be to approve the provision as proposed by NERC. As described herein, the proposed provision helps to ensure timely mitigation of GMD vulnerabilities in accordance with Order No. 830 while accounting for the circumstances under which Corrective Action Plan deadlines cannot be met. NERC provides the following comments on the proposals discussed in the NOPR.

A. Corrective Action Plans for Supplemental GMD Vulnerability Assessments

1. NOPR

In the NOPR, the Commission stated that proposed Reliability Standard TPL-007-2 addresses the Commission's directive in Order No. 830 in that it requires entities to assess their systems' vulnerabilities to the supplemental GMD event, a second planning event that is not based solely on spatially-averaged data and which is intended to capture the localized peak effects of GMDs.[15] The Commission, however, expresses concern that the proposed standard

[15] *Id*. at PP 23-24.

does not require entities to develop and implement a formal Corrective Action Plan to mitigate such vulnerabilities.[16] Specifically, the Commission stated:

> Moreover, in Order No. 830, 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." NERC's proposal to modify the benchmark, but then allow applicable entities the discretion to take corrective action based solely on the results of the spatially-averaged benchmark analysis while taking under advisement ("an evaluation of possible actions") the results of the supplemental assessment, does not satisfy the clear intent of the Commission's directive.[17]

While expressing support for the technical basis underlying the proposed supplemental GMD event, the Commission nevertheless expresses skepticism regarding NERC's assertion that requiring mandatory Corrective Action Plans would be premature at this time.[18] The Commission therefore proposes to direct NERC to modify proposed Reliability Standard TPL-007-2 to establish requirements for entities to develop and complete Corrective Action Plans for vulnerabilities identified through supplemental GMD Vulnerability Assessments.[19] The Commission proposes to direct NERC to file the revised standard within 12 months of the effective date of Reliability Standard TPL-007-2.

2. Comments

NERC supports the Commission's proposal to approve the proposed standard and the new supplemental GMD event. As the Commission states in the NOPR, the proposed

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16 *Id*. at P 24. Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.3 provides that, if the analysis concludes there is Cascading caused by the event, the entity shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

17 *Id*. at P 33 (internal citation omitted).

18 *See id*. at PP 35-39.

19 *Id*. at P 24.

supplemental GMD event builds on the same framework as the approved benchmark GMD event, but with some modifications to account for localized peak effects of GMDs. The proposed standard offers a reasonable approach for meeting the Commission's Order No. 830 directive to develop a GMD planning event that is not based solely on spatially-averaged data. NERC, however, has several concerns regarding the basis for the Commission's proposal to require entities to develop and implement formal Corrective Action Plans for vulnerabilities identified through GMD Vulnerability Assessments based on the supplemental GMD event. For these reasons, which are explained below, NERC does not support the Commission's NOPR proposal to modify the standard. NERC respectfully requests that the Commission accept NERC's commitment to conduct a formal review of the standard following the completion of the GMD Research Work Plan in lieu of including any standard modification directives in a final rule in this proceeding.

a) As Proposed, Reliability Standard TPL-007-2 Provides Strong Protection against the Reliability Risks of GMDs

Proposed Reliability Standard TPL-007-2 provides strong protection against the potential system-wide impacts of a severe GMD event consistent with both Order No. 779[20] and Order No. 830.[21] The proposed standard requires entities to assess their vulnerabilities using two defined GMD planning events intended to model the system-wide and potential localized impacts of a severe GMD storm. Using the approved benchmark GMD event, entities will

[20] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013) (directing NERC to develop one or more Reliability Standard "that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole"); *and* Order No. 830 at P 44 (approving Reliability Standard TPL-007-1, but directing NERC to revise the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data).

[21] Order No. 830 at P 44.

identify the potential system-wide impacts of a severe, 1-in-100 year GMD event. The proposed supplemental GMD event is intended to "supplement" the benchmark GMD event by providing a means to evaluate localized enhancements of a geomagnetic field during a severe GMD event that could potentially affect the reliable operation of the Bulk-Power System. It has been observed that severe GMD events may include peak geomagnetic fields of limited duration in a given local area, which decrease in intensity over distance.[22] The associated impacts could include increased reactive power loss and hot spot heating in some power transformers or voltage depressions in a local area.

If vulnerabilities are identified through either one of these assessments, entities are required to take action. Entities must develop Corrective Action Plans if their studies based on the benchmark GMD event identify potential voltage collapse, Cascading, or uncontrolled islanding. Under proposed Reliability Standard TPL-007-2, entities would be required to implement their selected mitigation measures on the timeline provided by the Commission in Order No. 830. If an entity determines, through its supplemental GMD Vulnerability Assessment, that a severe GMD event with localized enhancements of the geomagnetic field could impact a selected location and cause Cascading, then the entity's supplemental GMD Vulnerability Assessment must include an evaluation of "possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s)."[23] This evaluation is not merely advisory, but rather supports a range of potential mitigating actions, such as additional hardware mitigation, operating procedures, or other resilience actions to enhance recovery and restoration.

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22 *See* Petition, Ex. I (Supplemental GMD Event Description White Paper) at 8.

23 Petition, Attachment A, Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.3.

Furthermore, some of the mitigating actions identified through this evaluation would directly support mitigation that is required by other NERC Reliability Standards. Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.4 would require each applicable planning entity to convey information from its GMD planning studies to its Reliability Coordinator. Reliability Standard EOP-010-1 Requirement R1 Part 1.1 requires the Reliability Coordinator to implement GMD Operating Plans that include "activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area."[24] Such activities could include posturing the system to minimize GIC flows or tolerate increased reactive power losses, increasing operator situational awareness to respond to abnormal conditions, or preparing emergency or restoration plans for effective restoration following the event.[25] A supplemental GMD Vulnerability Assessment could, for example, identify load shedding plans that would prevent Cascading or identify additional at-risk transformers not identified through the benchmark GMD Vulnerability Assessment that should be protected with operating measures during a severe GMD event with localized peak geoelectric fields. The proposed standard would thus require the exchange of information to support the development of GMD Operating Plans that are based on detailed system studies and risk analysis.

Taken together, the GMD Vulnerability Assessments and Corrective Action Plans required by TPL-007-2 and the Operating Procedure requirements contained in EOP-010-1 provide a layered and effective approach to addressing the risks from severe GMD events. Given

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[24] Reliability Standard EOP-010-1 Requirement R1 Part 1.1, https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-010-1.pdf.

[25] Examples of possible actions to include in Operating Procedures are described in the NERC GMD Task Force Phase 2, Operating Procedure Template (Jan. 16, 2013), https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMDTF_Phase_2-Operating_Procedure_Template-Transmission%20Generation.pdf.

the relationship between the supplemental and benchmark GMD events, NERC anticipates that that Corrective Action Plans, when needed to address performance requirements for the benchmark GMD event, will also provide a large degree of protection to the Bulk-Power System for events with locally-enhanced geomagnetic fields. Operating Procedures based on analysis of the supplemental GMD event would help prepare operators for specific localized effects of severe GMD events that have the potential to impact the reliable operation of the Bulk-Power System.

In summary, the proposed standard provides a conservative and rigorous approach for assessing the known characteristics of a severe GMD event on the reliable operation of the Bulk-Power System and for taking appropriate measures to mitigate the effects of such an event. NERC believes that the proposed standard addresses the Commission's concerns from Order No. 779 and Order No. 830, and requests that the standard be approved without modification.

b) The Proposed Standard Provides a Reasonable Approach for Addressing Extreme Localized GMD Peak Effects

As described in the previous section, proposed Reliability Standard TPL-007-2 provides strong protection against the potential reliability risks of severe GMD events, consistent with both Order No. 779 and Order No. 830. The Commission has nevertheless expressed concern in the NOPR with NERC's proposed approach for addressing vulnerabilities to the supplemental GMD event. NERC maintains that the standard provides a reasonable approach for evaluating and mitigating the potential reliability impacts of peak GMD effects. This approach is based on, and accounts for limitations in, the current state of scientific and technical knowledge.

NERC is concerned that the Commission's proposal to require the development and implementation of Corrective Action Plans for the supplemental GMD Vulnerability Assessment would result in the *de facto* replacement of the benchmark GMD event with the proposed

supplemental GMD event. The proposed supplemental GMD event was neither developed nor intended to replace the benchmark GMD event in this manner. Further, should the proposed supplemental GMD event be applied to an overly-large area, it would represent an event significantly more extreme than a 1-in-100 year GMD event. Unlike the benchmark GMD event, which is intended to represent the impacts of a 1-in-100 year storm on the Bulk-Power System, the supplemental GMD event is meant solely to simulate the impacts from an extreme localized GMD effect if local turbulent solar activity amplifies the local voltages centered on a particular select area identified by the planner. There are several reasons why replacing the benchmark GMD event for the proposed supplemental GMD event would not promote prudent, cost-effective, risk-based system planning. In light of these concerns, which are described more fully below, NERC does not support the Commission's proposed directive. NERC maintains that the better approach would be to continue the scientific and engineering evaluation of geoelectric field enhancements, as outlined in the GMD Research Plan and further described below, before considering further revisions to the mandatory and enforceable requirements in the TPL-007 standard.

Proposed Reliability Standard TPL-007-2 carries forward the approach of approved Reliability Standard TPL-007-1 of requiring entities to assess their vulnerabilities to the benchmark GMD event and to develop and implement Corrective Action Plans to address identified system vulnerabilities. Since its development, the approved benchmark GMD event remains strongly supported as representative of a severe 1-in-100 year GMD event for assessing impacts on the Bulk-Power System.[26] The proposed supplemental GMD event can be thought of

[26] Since NERC filed its petition for approval of TPL-007-1 and the benchmark GMD event in 2014 in Docket No. RM15-11-000, similar extreme value analysis of magnetometer data has been performed by researchers at the Geomagnetic Laboratory, Natural Resources Canada. This analysis affirms the selection of the peak geoelectric field

as the benchmark GMD event, but with an amplified magnetic field in a localized area and with a finite time duration to simulate extreme localized GMD effects. It was developed, in response to Order No. 830, to provide a means to model the type of localized enhancement observed during some severe GMD events. An entity's supplemental GMD Vulnerability Assessment would be similar to its benchmark GMD Vulnerability Assessment, but it would employ a higher peak geoelectric field in all or part of the area studied, depending on the size of the enhanced area that the entity assumes and the modeling capabilities and approach it employs. While the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis for requiring Corrective Action Plans.

Specifically, while the geoelectric field magnitudes for both the benchmark and supplemental GMD events are rigorously defined using similar data sets and statistical analysis techniques, the added dimension of geographic size associated with the locally-enhanced magnetic field in the supplemental GMD event is only generally characterized due to the limited number of events and data available to characterize the phenomenon. For this reason, the TPL-007-2 standard drafting team included general guidance for assessing enhancements in areas occupying "a relatively narrow band of geomagnetic latitude (on the order of 100 km) and wider longitudinal width (on the order of 500 km)" but noted that these values are "reasonable but not

values for the benchmark GMD event. Results of the study using over 40 years of geomagnetic field data from Canadian observatories estimate the 100-year peak geoelectric field at reference location to be slightly less than the 8 V/km specified in the benchmark GMD event. Furthermore, the researchers used individual station geomagnetic field data without averaging over areas (i.e., the research was not based on spatial averaging). *See* L. Nikitina et al., *Assessment of extreme values in geomagnetic and geoelectric field variations for Canada*. 14 SPACE WEATHER 481-494 (2016) (the 100-year geoelectric field value for Ottawa is 2.8 V/km, which is 5 V/km at the reference latitude of 60 degrees geomagnetic latitude). Research being performed as part of the GMD Research Work Plan and by other organizations such as Natural Resources Canada continue to be useful in evaluating the benchmark GMD event used in the TPL-007 standard.

definitive."[27] As the Commission notes, the proposed standard affords flexibility to entities to determine the geographic size of the supplemental GMD event.[28] The type of mitigation that may be required for the supplemental GMD event could vary significantly, however, depending on how and where the planner models the localized enhancement. Further, based on its extensive experience in system planning and the relative immaturity of tools and methods for modeling localized enhancements, the TPL-007-2 standard drafting team determined that many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area.[29] By assuming that the localized extremes would be expansive, and not confined in area and impact, entities would be assessing their vulnerabilities to an event estimated to be highly unlikely, more extreme than a 1-in-200 year event. NERC does not believe that the Commission intended in Order No. 830 for a NERC Reliability Standard to require entities to develop Corrective Action Plans to provide complete mitigation for all potential vulnerabilities identified by applying localized peak values over an entire planning area in this way,[30] nor would such an approach necessarily promote the interests of prudent system planning.

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[27] Petition at 11-13 and Ex. I (Supplemental GMD Event Description White Paper) at 13.

[28] NOPR at P 36.

[29] *See* Petition, Exhibit I (Supplemental GMD Event Description White Paper) at 13.

[30] *See* Order No. 830 at P 36, in which the Commission explained the NOPR proposal underlying its directive as follows (emphasis added):

> Specifically, the NOPR proposed to direct NERC to modify the reference peak geoelectric field amplitude component of the benchmark GMD event definition so that it is not calculated based solely on spatially-averaged data. The NOPR explained that this could be achieved, for example, by requiring applicable entities to conduct GMD Vulnerability Assessments (and, as discussed below, thermal impact assessments) using two different benchmark GMD events: the first benchmark GMD event using the spatially-averaged reference peak geoelectric field value (8 V/km) and the second using the non-spatially averaged peak

NERC does not believe that concerns regarding the uncertainty of the geographic size of the supplemental GMD event could be addressed adequately by sensitivity analysis or through other methods in planning studies.[31] Sensitivity analysis can be useful component of planning studies. However, as many entities are performing GMD studies using complex engineering and geophysical models for the first time, there are inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) that may be subject to sensitivity analysis and would produce differences in GMD Vulnerability Assessment results. NERC believes introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments. Such issues would be better addressed through research.

Further, while some commercially-available modeling tools now advertise capabilities that could be used to model localized GMD enhancements,[32] to NERC's knowledge these capabilities have not been used extensively by planners, nor have the different software tools

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> geoelectric field value cited in the GMD Interim Report (20 V/km). The NOPR stated that the revised Reliability Standard could then require applicable entities to take corrective actions, using engineering judgment, based on the results of both assessments. **The NOPR explained that applicable entities would not always be required to mitigate to the level of risk identified by the non-spatially averaged analysis; instead, the selection of mitigation would reflect the range of risks bounded by the two analyses, and be based on engineering judgment within this range, considering all relevant information.** The NOPR stated that, alternatively, NERC could propose an equally efficient and effective modification that does not rely exclusively on the spatially-averaged reference peak geoelectric field value.

See also NOPR at P 40 ("[W]e agree with NERC that any required mitigation of supplemental GMD event vulnerabilities should be flexible in terms of how applicable entities choose to mitigate such vulnerabilities.").

[31] *See Id*. at P 36 ("NERC contends that the low number of real-world observations on which the supplemental GMD event is based calls into question the accuracy of its geographic size. However, any uncertainty regarding the size of the geographic footprint of the supplemental GMD event could be addressed by applicable entities through sensitivity analysis and other methods within planning studies.").

[32] *See Id*. at P 38 and n.47 (citing two examples of modeling suites that advertise this capability).

been benchmarked for consistency in results. Furthermore, underlying assumptions related to the size and spatial characteristics of the enhancement are the subject of ongoing research. NERC anticipates that these tools and capabilities will continue to evolve and mature, and it will continue to support such efforts through the NERC GMD Task Force. Given the variations in modeling localized peak enhancements, it is appropriate for the TPL-007 standard to continue to require the development of Corrective Action Plans, plans which could call for extensive planning and capital expenditures, only for the benchmark GMD Vulnerability Assessments.

To conclude, NERC maintains that the proposed standard strikes the appropriate balance between the urgency to address GMD-related vulnerabilities and providing flexibility consistent with principles of prudent, cost-effective, risk-based system planning. By requiring the entity to evaluate which actions can be taken to address vulnerabilities to the supplemental GMD event, the standard maintains a high bar for reliability. At the same time, the standard affords the entity sufficient flexibility to determine whether to supplement an existing Corrective Action Plan based on the benchmark GMD event with additional measures based on its engineering judgment and in light of any other relevant considerations. The proposed standard thus addresses the Commission's concerns from Order No. 830 in a clear, rigorous, results-based Reliability Standard.

c) NERC's Review of the TPL-007-2 Standard Provides the Proper Forum for Evaluating the Standard in Light of New Technical and Scientific Understanding

In Order No. 830, the Commission directed NERC to perform activities to improve scientific and technical understanding of GMD events. In response, NERC developed and submitted to the Commission its Order No. 830 GMD Research Work Plan. NERC is currently executing this plan, which includes several Tasks relevant to the issues identified in this NOPR. Specifically, Task 1 – *Further Analyze Spatial Averaging Used in the Benchmark GMD Event*

consists of two main research components: (i) research to improve understanding of the characteristics and spatial scales of localized geoelectric field enhancements caused by severe GMD events; and (ii) research to determine the impacts of spatial averaging assumptions on BPS reliability.[33] One aim of the research is to improve understanding of characteristics and spatial scales of localized geoelectric field enhancements, which could inform the supplemental GMD event.

NERC is concerned that the timing of the Commission's proposed directive (i.e., to submit a revised standard 12 months following the effective date of TPL-007-2) could, depending on the effective date of a final rule in this proceeding, require NERC to initiate development of a revised standard prior to the completion of its important and directly relevant GMD research work. As explained in more detail in NERC's GMD Research Work Plan filing, NERC expects that the last of the project's deliverables will be ready by early 2020. Any scientific research project schedule, however, must account for the possibility that additional time may be needed to explore potential findings or amend project approaches to provide more useful results. NERC also needs to account for additional time, following delivery of the technical reports and other project deliverables, to allow interested entities an opportunity to review and provide comments consistent with the Commission's guidance.[34] These comments could provide additional insights and further areas for consideration. For these reasons, NERC does not anticipate that the GMD Research Work Plan would be fully completed before late 2020, even assuming that the work proceeds generally as scheduled. NERC believes that it is important that this work be completed in full prior to considering further revisions to the TPL-007 standard.

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[33] *See* GMD Research Work Plan, *supra* note 5, at 2-7.

[34] In its Order accepting NERC's preliminary plan, the Commission stated that it "expects NERC to afford interested entities an opportunity to comment on GMD Work Plan deliverables before they are filed with the Commission." *Order on GMD Research Work Plan*, 161 FERC ¶ 61,048, at P 17 (2017).

As noted earlier in these comments, NERC commits to initiate a review of TPL-007-2 following the completion of the GMD Research Work Plan to evaluate whether the standard continues to be supported by the available knowledge or whether additional refinements are necessary. This review could result in modifications to, or additional support for, the proposed supplemental GMD event, and thereby inform what the TPL-007 standard should require in terms of mitigation based on supplemental GMD Vulnerability Assessments. To promote the efficient use of standard development resources and to avoid the burden associated with implementing multiple successive versions of a standard, NERC respectfully requests that the Commission await the completion of NERC's GMD research work and NERC's subsequent review prior to issuing any directives requiring further modifications to the standard.

B. Extending Corrective Action Plan Deadlines

1. NOPR

In the NOPR, the Commission expressed concern that proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.4, which allows entities to extend their Corrective Action Plan deadlines in limited circumstances, "contrasts with the Commission's guidance in Order No. 830 that 'NERC should consider extensions of time on a case-by-case basis.'"[35] The Commission stated that it "agree[s] with NERC that there should be a mechanism for allowing extensions of … deadlines," but that it would like to "avoid unnecessary delay in implementing protection against GMD threats."[36] The Commission, therefore, seeks comments on two proposals to address the situation where an entity cannot complete the implementation of a

[35] NOPR at P 45 (citing Order No. 830 at P 102).

[36] *Id.* at P 46.

Corrective Action Plan to address GMD vulnerabilities within the timetable specified by proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3.[37]

Under the first option, the Commission proposes to direct NERC to modify the standard to require NERC and the Regional Entities to consider any requests for extension of time on a case-by-case basis. Entities seeking an extension of Corrective Action Plan deadlines would be required to submit a request to NERC and the Regional Entities containing the information that would be required by proposed TPL-007-2 Requirement R7 Part 7.4. In addition, the Commission would direct NERC to submit a report addressing the disposition of any such requests and the circumstances under which entities are exceeding Corrective Action Plan deadlines within 12 months from the date on which applicable entities must comply with the last requirement of TPL-007-2, following which the Commission would determine whether further action is necessary.[38]

Under the second option, the Commission would approve proposed TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC. The Commission would also direct NERC to submit a report regarding how often and why entities are exceeding Corrective Action Plan deadlines within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2, following which the Commission would determine whether further action is necessary.[39]

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[37] As directed by the Commission in Order No. 830, proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3 provides that each Corrective Action Plan required by the standard shall include a timetable that specifies completion of non-hardware mitigation within two years of from the development of the Corrective Action Plan and completion of hardware mitigation within four years from the development of the Corrective Action Plan.

[38] NOPR at P 50.

[39] *Id*. at P 51.

2. Comments

NERC supports the Commission's second proposal; that is, to approve Reliability Standard TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC. Proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3 accomplishes the Commission's overarching goal from Order No. 830 of assuring timely mitigation of GMD vulnerabilities in accordance with the Commission's specified deadlines. Proposed Requirement R7 Part 7.4 accounts for the circumstances under which meeting those deadlines may not be achievable. Placing these requirements into the standard provides clarity and certainty regarding when an entity may extend a Corrective Action Plan mitigation deadline and what steps must be followed to maintain accountability and thus compliance with the standard. This standards-based approach also avoids the administrative burden, uncertainty, and further delay that could be associated with implementing a new ERO adjudication process, such as one that would be dedicated to evaluating GMD Corrective Action Plan deadline extensions on a case-by-case basis.

NERC shares the Commission's concern, as stated in Order No. 830 and reiterated in the NOPR, that entities should not unnecessarily delay efforts to mitigate identified GMD vulnerabilities. NERC submits that proposed Requirement R7 Part 7.4 accounts for this concern. Under the proposed provision, an entity may extend a Corrective Action Plan deadline only where "situations beyond the control of the responsible entity" are the cause for delay. Such situations could include lengthy legal or regulatory processes, stakeholder processes required by tariff, or long equipment lead times, to cite a few examples. The proposed provision was drafted with the goal of providing entities with sufficient flexibility to choose the optimal mitigation strategies for their areas; it is not so flexible, however, as to allow entities to extend Corrective Action Plan deadlines indefinitely or for any reason whatsoever. As part of the compliance monitoring and enforcement activities for the proposed standard, NERC and Regional Entity

staff would exercise their authority to review the reasonableness of any Corrective Action Plan delay, including reviewing the "situations beyond the control of the responsible entity" that are cited as causing the delay.

The proposed provision also contains requirements to maintain accountability when entities extend Corrective Action Plan deadlines. These steps include documenting, in the Corrective Action Plan itself, the circumstances that are causing the delay in implementing the selected mitigation, a description of any changes to the original plan or prior revised plan(s), and revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected options. The entity would be required to update its plan at least every 12 months until implemented. Additionally, under Requirement R7 Part 7.5, an entity would be required to provide the revised plan to its Reliability Coordinator as well as other recipients of the original plan within 90 days of the revision.

Both NERC's proposed standard-based approach and the Commission's proposed "case by case" determination approach would promote timely mitigation of GMD vulnerabilities subject only to reasonable and limited exceptions. The standard-based approach, however, would provide several benefits a case-by-case adjudication model would not. First, if approved, the proposed provision would be monitored through well-established ERO Enterprise Compliance Monitoring and Enforcement Program processes, along with the other Requirements of the proposed TPL-007 standard. If the Commission adopted its first proposal and required NERC to pre-approve individual Corrective Action Plan extensions and plan updates instead, NERC may need to develop and implement a new ERO adjudication process specifically for evaluating

GMD Corrective Action Plan extension requests.[40] Second, the standard-based approach imposes no more administrative burden than is necessary for reliability. In this particular context, a case-by-case adjudication model would likely result in a greater administrative burden to registered entities and NERC and the Regional Entities alike, for no additional reliability benefit. Lastly, the standard-based approach prioritizes timely completion of the actions entities have chosen to mitigate their GMD vulnerabilities. NERC is concerned that the uncertainty associated with a case-by-case adjudication model could result in entities further delaying action to implement their selected GMD mitigation actions while they await the results of a NERC or Regional Entity determination or appeal.

While NERC maintains that proposed Requirement R7 Part 7.4 accomplishes the reliability goal of timely GMD mitigation efficiently and effectively, NERC agrees that a report describing the results of NERC's monitoring of this provision could provide useful information. NERC therefore commits to file the report proposed by the Commission in the NOPR.[41] Specifically, NERC commits to prepare and submit to the Commission a report that describes how often and the reasons why entities in the United States are exceeding Corrective Action Plan deadlines. NERC commits to file this report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2.

[40] One model for such a process could be the Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System, Appendix 5C to the NERC ROP.

[41] *See* NOPR at P 51.

III. Conclusion

For the reasons set forth above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Lauren A. Perotti

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Date: July 23, 2018

CERTIFICATE OF SERVICE

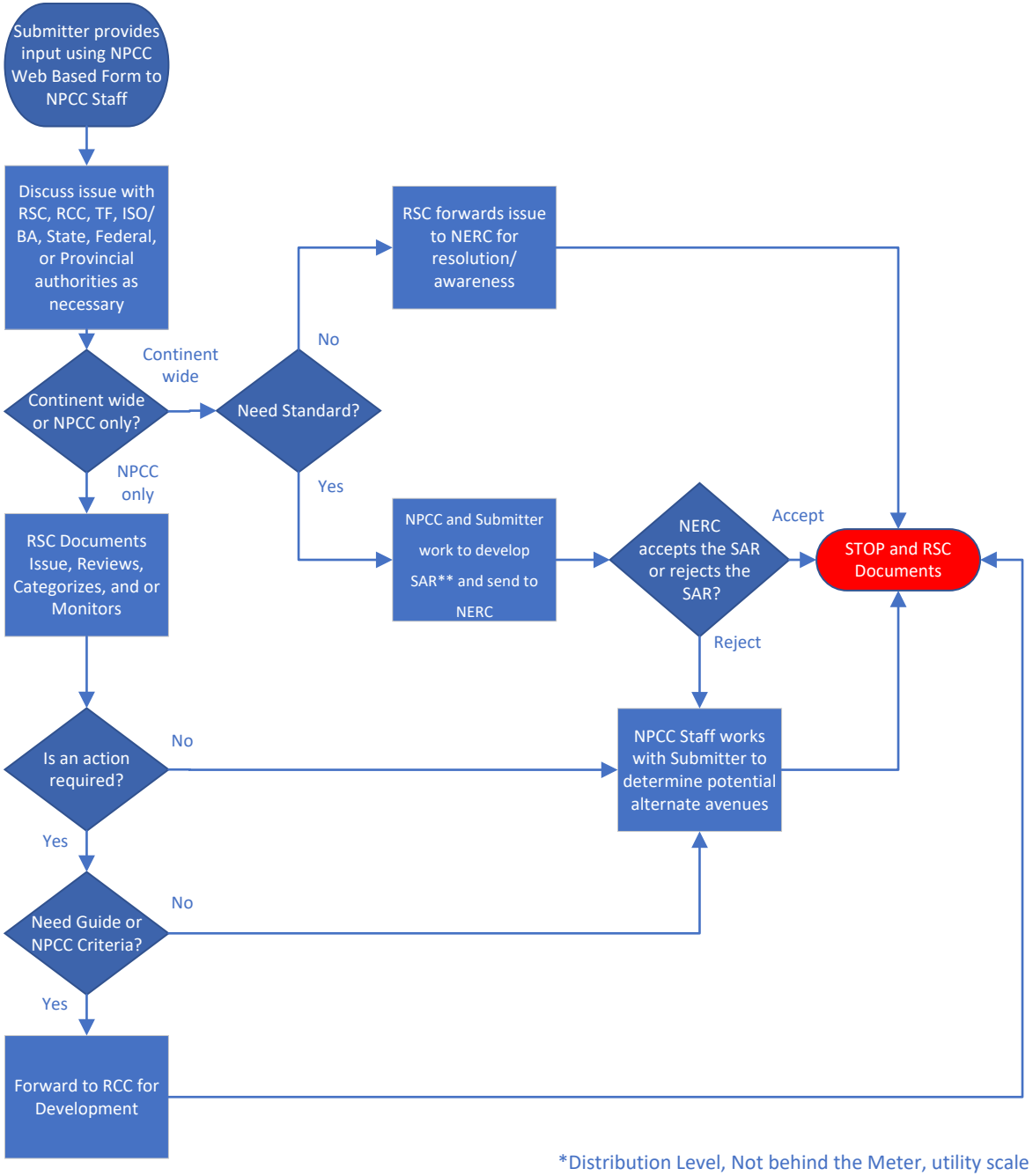
I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C. this 23rd day of July, 2018.

/s/ Lauren A. Perotti

Lauren A. Perotti

Counsel for the North American Electric Reliability Corporation

Impacts from Distribution Level* Distributed Energy Resources on the BES



*Distribution Level, Not behind the Meter, utility scale DER

** Standards Authorization Request (SAR)

NPCC, Inc.

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

PLEASE COMPLETE AND EMAIL THIS FORM TO; NPCCSTANDARD@NPCC.ORG

DISTRIBUTED ENERGY RESOURCE (DER), BES IMPACT REPORTING FORM

Name		**Date**	
Email		**Company**	
Impact on Bulk Electric System		**Area (NY, NE, State or Province etc.)**	

TYPES OF EQUIPMENT IMPACTED

Equipment Type	**Location (Optional)** (substation name, etc.)	**Impact** (Positive reliability impact? Negative reliability impact-Protection System failure, Misoperation, load affected or lost?, power quality issue?, etc)	**Duration of Impact,** (start and stop times, length of impact, ongoing? etc.)

DESCRIPTION OF IMPACT ON BES- WHAT HAPPENED OR WAS OBSERVED?

Please describe below the details of all the impacts of the DER as it pertains to this report, such as load loss, loss of life, equipment failure or potential reliability improvement. A sequence of events showing the impact is helpful. Attach supporting information to this form if necessary (Optional).

ROOT CAUSE OR ADDITIONAL ANALYSIS

Please describe below the details of any investigation your company may have already done to identify causes or contributing factors to the incident. This will help NPCC route the issue properly to address it.

NPCC REVIEW OF ISSUE AND RECOMMENDATIONS (I.E. REFER TO NERC, DEVELOP A CRITERIA GUIDELINE, ALREADY ADDRESSED OR IDENTIFIED, ETC.)

NPCC Date of Resolution of Issue _____

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Efficiency Review (SER) Recommendations for Retirement-Draft		
Date Submitted:			
SAR Requester			
Name:	Standards Efficiency Review (SER) Team		
Organization:			
Telephone:		Email:	
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard(s) ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This SAR Identifies candidate requirements that are not essential for reliability and could thereby reduce regulatory obligations and/or compliance burden.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
A specific list of proposed requirements recommended for retirement are provided in the project scope.			

Project Scope (Define the parameters of the proposed project):
The Real-time Operations Standards Efficiency Review Team suggests that the following requirements in their perspective NERC Standards be retired, as they have been assessed as having no reliability benefit.

- BAL-005-1 R4, R6
- COM-002-4 R2
- EOP-005-3 R8
- EOP-006-3 R7
- FAC-003-4 R5, R6, R7
- FAC-008-3 R7, R8
- FAC-013-2 R1, R2, R4, R5, R6 (All)
- INT-004-3.1 R1, R2, R3
- INT-006-4 R3.1, R4, R5
- INT-009-2.1 R1, R2, R3
- INT-010-2.1 R1, R2, R3
- IRO-002-5 R1, R4, R6
- IRO-006-5 R1
- IRO-008-2 R6
- IRO-014-3 R3
- MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All)
- MOD-001-2 R1, R2, R3, R4, R5, R6 (All)
- MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All)
- MOD-008-1 R1, R2, R3, R4, R5 (All)
- MOD-020-0 R1
- MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All)
- MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All)
- MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All)
- NUC-001-3 R1
- PRC-004-5(i) R4
- PRC-015-1 R1, R2, R3 (All)
- PRC-018-1 R1, R2, R3, R4, R5, R6 (All)
- PRC-019-2 R1
- TOP-001-4 R16, R17, R19, R22
- VAR-001-4.2 R2, R3
- VAR-001-4.2 E.A.15

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):

The observations of the Standards Efficiency Review (SER) Team related to each of the requirements above are listed below as a rationale for retirement. The SER Project divided into three teams; Real-time Operations (RT), Long-term Planning (LT), Operations Planning (OP)

BAL-005-1. R4, R6 (RT)

This reliability objective is duplicated in TOP-010-1(i) R2:

Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include:

2.1. Criteria for evaluating the quality of Real-time data;
2.2. Provisions to indicate the quality of Real-time data to the System Operator; and
2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

The BA is already required by TOP-010-1(i) R2 to have an Operating Process/Procedure to address quality of Real-time data (which would include Reporting ACE) which includes criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities.

The same logic applies for R6 since TOP-010-1(i) R2 requires an Operating Process/Procedure to include criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities

COM-002-4 R2 (RT)

The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training within the PER-005-2 Standard.

EOP-005-3 R8 (OP)

The requirement should be retired because the related compliance activities are duplicative of the activities covered by the Systematic Approach to Training within the PER Standards. The team also agrees that the requirement to provide at least two-hours of training is arbitrary. The training objective should be to assure thorough training such that System Operators are certified and competent to perform restoration activities. At minimum, as noted in the SER Operations Planning team comments on EOP-005-3 R8, we agree that EOP-006-3 R7 requirement can be retired and the

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

content from this requirement transferred into PER-005-2 (and eventually into PER-005-3 when PER-005-3 is approved and becomes mandatory). The SER teams believes that system restoration would certainly fall within an entity's systematic approach to developing and implementing a training program for its System Operators and system restoration would very likely be included within the entity's reliability-related task list.

EOP-006-3 R7 (OP)
The SER Operations Planning team believes this requirement should be retired because the related compliance activities are duplicative of the activities covered by the Systematic Approach to Training within the PER Standards. The SER teams believes that system restoration would certainly fall within an entity's systematic approach to developing and implementing a training program for its System Operators and system restoration would very likely be included within the entity's reliability-related task list. The attributes of the PER training should cover the tasks in EOP-006 R1.

FAC-003-4 R5, R6, R7 (OP)
R1 and R2 fulfil the purpose of the standard through measurable actions. R5, R6, and R7 are controls to support R1 and R2. Removal of R5, R6, and R7 do not pose a risk to BES as long as R1 & R2 remain. These three requirements appear to be more administrative of Good Utility Practice for vegetation management inside the ROW and do not provide any further protection for BES reliability over what R1 and R2 does. Also, the NERC Rules of Procedure allows consideration for extenuating circumstances relative to R5.

FAC-008-3 R7, R8 (OP)
FAC-008-3 R7 and R8 are redundant in nature when compared to requirements in other data sharing standards such as MOD-032, IRO-010, and TOP-003. In order for the RC and TOP to comply with FAC-014, data must be shared between the GO and RC/TOP and between the TO and RC/TOP. FAC-008-3 R7 and R8 can be retired without negatively impacting the reliability of the BES.

FAC-013-2 R1, R2, R4, R5, R6 (ALL) (LT)
The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities.
In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as Transmission Planners (TP), do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what is acceptable system performance.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.

- R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.
- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.

The 2013 NERC Independent Experts Review Project identified R2 and R3 as administrative and recommended them for retirement. R3 was approved for retirement by FERC in 2014.

INT-004-3.1. R1. (RT)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered function. The INT Periodic Review Team completed their analysis and determined the requirement is duplicative of the NAESB business practice standards. Covered in existing NAESB WEQ-004-1 and WEQ-004-5 and in proposed NAESB WEQ-004-1.8.

Requirement R1: (1) IERP recommended for retirement and (2) is duplicative because (a) language leading to the submittal of all RFI, which includes Dynamic Schedules and Pseudo-Ties, is contained in existing NAESB WEQ-004-1 and WEQ-004-5; and (b) the remaining element of Requirement R1, when Pseudo-Ties may be excluded, is contained in the NAESB proposed WEQ-004-1.8. The Independent Expert Review Team recommended the requirement be retired.

INT-004-3.1. R2. (RT)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered function. The INT Periodic Review Team completed their analysis and determined the requirement is duplicative of a currently proposed revision to the NAESB. duplicative as the language in R2 that requires Confirmed Interchange associated with Dynamic Schedules or Pseudo-Ties be updated for future hours when any of the three the conditions cited in the requirement occur is contained almost verbatim in the proposed NAESB WEQ-004-23. business practice standards. The Independent Expert Review Team recommended the requirement be retired.

INT-004-3.1 R1, R2, R3 (OP)
Interchange scheduling and congestion are elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Further, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity, has been removed from the list of NERC Functional Entities, supporting the market-based observations herein. Requirement R3 specifically refers to Pseudo-Ties that are included in the NAESB Electric Industry Registration, reinforcing the tie to NAESB.

INT-006-4. R3.1 (RT)
The SER Team and industry comments support the conclusion of the INT Periodic Review Team (PRT) (Project 2017-04) in that this requirement warrants retirement. The INT PRT found no impact on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. Additionally, RCs are notified via the electronic tag when a Reliability Adjustment Arranged Interchange is denied, as required in the NAESB e-Tagging Specifications. Therefore, this requirement is redundant and requires Responsible Entities to conduct an activity that does little, if anything, to benefit or protect the reliable operation of the BES. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-006-4 R3.1 (OP)
The SER Team and industry comments support the conclusion of the INT PRT who concluded this requirement should be retired. The INT PRT found little to no effect on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. Additionally, RCs are notified via the electronic tag when a Reliability Adjustment Arranged Interchange is denied, as required in the NAESB e-Tagging Specifications. Therefore, this requirement is redundant and requires Responsible Entities to conduct an activity that does little, if anything, to benefit or protect the reliable operation of the BES. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-006-4 R4 (RT)
The SER Team and industry comments support the conclusion of the INT PRT in that this requirement warrants retirement.as it is duplicative of the NAESB e-Tagging Specifications and is not a reliability related task performed by a Responsible Entity. Covered in NAESB e-Tagging specifications, Section 1.6.3.1 and Section 1.3. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-006-4 R4 (OP)
The SER Team and industry comments support the conclusion of the INT PRT who concluded this requirement should be retired as it is duplicative of the NAESB e-Tagging Specifications and is not a reliability related task performed by a Responsible Entity. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-006-4 R5 (RT)
The SER Team and industry comments support the conclusion of the INT PRT in that this requirement warrants retirement. as it is duplicative of the NAESB e-Tagging Specifications and is not a reliability related task performed by a Responsible Entity. Covered in NAESB e-Tagging specifications, Section 1.6.4. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-009-2.1 R2 (RT)
This requirement can be retired under Paragraph 81 criteria, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7:

Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with:

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,
7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

INT-009-2.1 R1, R2, R3 (OP)
Interchange scheduling and congestion are elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Retiring these elements will allow the TOPs and RCs to operate the system without concern for cost signals.

INT-010-2.1 R1, R3 (RT)
This requirement may be retired under Paragraph 81 Criteria B6 and B7, due to their inclusion in the NAESB Business Practice Standards with more stringent tagging requirements already exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative.

INT-010-2.1 R2 (RT)
This requirement may be retired under Paragraph 81 Criteria B6 and B7, due to their inclusion in the NAESB Business Practice Standards with more stringent tagging requirements already exist in NAESB WEQ-004-8. Therefore, this requirement is duplicative.

INT-010-2.1 R1, R2, R3 (OP)
Interchange scheduling and congestion are elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Moving these elements to NAESB will allow the TOPs and RCs to operate the system without concern for cost signals.

IRO-002-5 R1 (OP)
The requirement is solely a control for aiding compliance with IRO-008-2 R1 related to the performance of an Operational Planning Analysis (OPA) and it is duplicative to requirements R3 in IRO-010-2. The NERC Glossary of Terms definition of OPA requires certain data to be used for the analysis performed under IRO-008-2 R1 and standard IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to fulfill IRO-010-2 R3, it must be able to exchange data with the requesting RC. Additionally, to comply with IRO-008-2 R1, the RC

must have received all of the data it needs to perform the OPA. Finally, the measure (M1) for IRO-002-5 R1 states that an entity merely needs to show a piece of paper describing its data exchange capabilities with other entities, which is solely administrative in nature.

IRO-002-5 R4 (OP)
This requirement can be retired because the authority to approve/deny outages to any equipment, whether load carrying or not, is a fundamental attribute of the system operator role, and therefore does not contribute to reliability of the BES.

IRO-002-5 R6 (RT)
This is covered in R5. The requirement to monitor pre-supposes the ability (tools) to do so:

> *Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, 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 Coordinator Area.*

IRO-006-5 R1 (RT)
Each interconnection has their own TLR procedure within the NERC Reliability Standards. Therefore, IRO-006-5 is redundant and unnecessary. If an entity cannot respond to the RC's request it can notify them in accordance with IRO-001-4 R2:

> *Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.*

IRO-008-2 R6 (RT)
This requirement is administrative in nature and does not provide any justifiable benefits to system reliability. An Operating Plan would already include specific actions to notify.

IRO-014-3 R3 (RT)
The reliability objective of "notification" is duplicative and currently covered in the Notification requirement in R1 Part 1.1:

> *Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:*
>
> *1.1. Criteria and processes for notifications.*

MOD-020-0 R1 (LT)
NERC Reliability Standard MOD-020-0 Requirement R1 is a duplication of data provisions included in the demand and energy data specification standards, MOD-031 and IRO-010-2.

MOD-020-0 R1 requires requests by TO, BA, and RC to those applicable entities that are required to provide Interruptible Demand and Direct Control Load Management in compliance to load data requests.

In MOD-031-2 R1.4.5 requires the Planning Coordinator or Balancing Authority to request total available peak hour forecast of controllable and dispatchable Demand Side Management. Further, Requirement R2 specifies the obligation for each applicable entity identified in the data request to provide the requested data to the PC or BA.

In IRO-010-2 R1 requires the Reliability Coordinator to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments that, in Requirement R2, requires the RC to send a data request to applicable entities for their response to the data request.

Therefore, the SER Long-Term Planning team is supporting the retirement of MOD-020-0 R1 due to overlapping requirements of MOD-031-2 Requirement R1.4.5 and Requirement R2 and IRO-010-2 R1 and Requirement R2.

NUC-001-3 R1 (LT)
The requirement is administrative in nature as R1 actions are inherent in R2 since each entity 'shall have in effect' an agreement.

PRC-004-5(i) R4 (OP)
The SER Operations Planning team believes this requirement should be retired because the related compliance activities falls into tracking of milestones and do not improve reliability. An entity should always endeavor to determine the cause of a Misoperation, although doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigations using the same event data are unlikely to lead to additional observations unless additional misoperations occur of which will trigger a new investigation with additional event data.

PRC-015-1 R1, R2, R3 (All) (LT)
PRC-013-1 standard is inactive. Cannot measure compliance of R1 against PRC-013-1. Additionally, maintaining a list of RAS is an administrative requirement that does not contribute to the reliability of the BES. Soon to be superseded by PRC-012-2.

Requirement R2 references PRC-012-1 R1, which is no longer enforceable. Soon to be superseded by PRC-012-2.

Requirement R3 is soon to be superseded by PRC-012. In support of the Independent Expert Review Panel's (IERP) justification to retire the standard: "P81. Administrative/Documentation", this is an administrative requirement. RE and NERC already has authority to request such information.

PRC-018-1 R1, R2, R3, R4, R5, R6 (All) (LT)
This standard requires both the TO or GO to ensure that DME's installed per PRC-002-1 and meet specific criteria. PRC-002-1 was never approved by FERC but PRC-018 was approved on the basis that each RRO would establish a DME program and that even if PRC-002-1 were not approved; PRC-018 could be enforced per the RRO program. Most RRO's have retired their programs which establish the scope of DME's for this standard. Furthermore, there are differences in the methodologies used by the RRO's to establish scope of DME's and what is mandated by requirement R1 of PRC-002-2. The lists of DME's and where they are installed will differ from PRC-018-1 and PRC-002-2.

PRC-019-2 R1 (LT)
Requirement R2 already requires that any change that impacts the voltage regulating coordination be performed within 90 days of changes. If this requirement is followed, the five-year coordination is an unnecessary paper exercise with no reliability benefit once the initial coordination study has been completed.

TOP-001-4 R16, R17 (OP)
This requirement can be retired because the authority to approve or deny outages of any equipment, whether load carrying or not, is a fundamental attribute of the system operator role. This was recognized by NERC and FERC in Project 2007-03 where the authority language in former Standard TOP-001-1 R1 was removed from the revised TOP standards approved by both NERC and FERC.

TOP-001-4 R19 (OP)
The requirement is solely a control for aiding compliance with TOP-002-4 R1 related to the performance of an Operational Planning Analysis (OPA) and it is duplicative to requirements R5 in TOP-003-3. The NERC Glossary of Terms definition of OPA requires certain data to be used for the analysis performed under TOP-002-4 R1 and standard TOP-003-3 requires the TOP to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R3), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting TOP. Additionally, to comply with TOP-002-4 R1, the TOP must have received all of the data it needs to perform the OPA.

TOP-001-4 R22 (OP)
The requirement is solely a control for aiding compliance with TOP-002-4 R4 related to preparing Operating Plans and it is duplicative to requirement R5 in TOP-003-3. Standard TOP-003-3 requires the BA to identify the data it needs to perform its analysis functions (R2), which entities need to provide such data (R4), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting BA.

Additionally, to comply with TOP-002-4 R4, the BA must have received all of the data it needs to perform its analysis functions.

VAR-001-4.2 R2 (OP)
Retire due to duplicative to other requirements. Requirements R2 and R3 of VAR-001-4.2 are both related to maintaining the system within SOLs because a voltage limit is a form of SOL. TOP-002-4 already requires TOPs to identify where the potential SOL exceedances might occur for next-day operations and prepare a plan to mitigate these potential SOL exceedances, including notifying entities of their role in those plans (R3). When moving into real-time operations, the requirements of TOP-001-4 govern and the TOP continues to be obligated to operate within SOLs and direct the operation of the system to operate within SOLs or return to operation within SOLs. R1 of TOP-001-4 grants the TOP the authority to act and direct action to maintain reliability, including obtaining necessary reactive resources as described in VAR-001-4.2 R2. This requirement is also redundant with TOP-001-4 Requirements R1, R14 and R15.

VAR-001-4.2 R3 (OP)
The language of requirement R3 of VAR-001-4.2 is adequately covered by the following existing NERC standard requirements:

- The actions taken by the registered TOP under R3 are the same actions required of the TOP under TOP-001-4 R1, which states that the TOP "shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions." The requirement to "act" using all available actions, whether by "its own actions" or by the actions of others via "issuing Operating Instructions" is the same as "operate or direct ... operation of devices to regulate ... voltage and reactive flow."

- The purpose of the actions taken by the TOP under R3 is the same purpose accomplished by TOP-001-4 R1, R10, R12, R13 and R14 by acting to operate within limits (SOLs and IROLs) to maintain reliability of its transmission system.

VAR-001-4.2 E.A.15 (RT)
This requirement is applicable to WECC only. The same requirement exists in VAR-002-4.1 R2.3 that is applicable to the ERO:

> *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.*

Additionally, the following Standards and Requirements were consolidated into MOD-001-2 in project 2012-05, which was filed for regulatory approvals on February 10, 2014, and is still pending approval. We recommend that NERC withdraw the February 10, 2014 petition related to MOD-001-2.

MOD-001-1a – R1, R2, R3, R4, R5, R6, R7, R8, R9 (OP)
Flowgates, transfer capability, and congestion are all elements that impact transmission costs, rather than actual management of the BES. Transmission Operators, Balancing Authorities, and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues.

MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (OP)
Flowgates, transfer capability, and congestion are all elements that impact transmission costs, rather than actual management of the BES. Transmission Operators, Balancing Authorities, and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. In addition, Requirement R3 specifically refers only to the Load Serving Entity, which has been removed from the list of NERC Functional Entities. Project 2012-05 proposes retirement of Requirements R4 (and subparts), R6 (and subparts), and R10.

MOD-008-1 R1, R2, R3, R4, R5 (OP)
Transmission Reliability Margin is an element that impacts transmission costs, rather than actual management of the BES, in that it preserves addresses transfer capability. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues.

MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (OP)
Flowgates, transfer capability, and congestion are all elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Project 2012-05 notes that requirements R4.2, R6.3, R6.4, R8, R9, and R10 all address “commercial arrangements” and recommends retirement of these requirements.

MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (OP)
Flowgates, transfer capability, and congestion are all elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Project 2012-05 notes that requirements R2.2, R2.3, R2.6, R5, and R6 address “business practices”, “commercial arrangements” or “contractual obligations” and recommends retirement or substantial modification of these requirements.

MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (OP) Flowgates, transfer capability, and congestion are all elements that impact transmission costs, rather than actual management of the BES. Transmission Operators and Reliability Coordinators must operate the system in such a way that it's reliable, both for current operations and for contingency conditions, and must remain agnostic (according to FERC Standards of Conduct) to cost-related issues. Project 2012-05 notes that R6 addresses "commercial arrangements" and recommends retirement of this requirement.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The team did not identify any known cost impacts.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
No unique characteristics of the BES facilities that may be impacted by this proposal were identified by the SER team.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
All.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
SER Project Team(s)
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
None identified by the SER team.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	None identified.

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC – 024 – 2 Generator Frequency and Voltage Protective Relay Settings		
Date Submitted:	5/29/2018		
SAR Requester			
Name:	Keith E. Casey, Ph.D., Vice President, Market and Infrastructure Development		
Organization:	California Independent System Operator Corporation (CAISO)		
Telephone:	(916) 608-7125	Email:	kcasey@caiso.com

SAR Type (Check as many as apply)

- ☐ New Standard
- ☒ Revision to Existing Standard
- ☐ Add, Modify or Retire a Glossary Term
- ☐ Withdraw/retire an Existing Standard
- ☐ Imminent Action/ Confidential Issue (SPM Section 10)
- ☐ Variance development or revision
- ☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)

- ☐ Regulatory Initiation
- ☐ Emerging Risk (Reliability Issues Steering Committee) Identified
- ☐ Reliability Standard Development Plan
- ☐ NERC Standing Committee Identified
- ☐ Enhanced Periodic Review Initiated
- ☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

NERC convened the Inverter based Resource Performance Task Force (IRPTF) shortly after it became clear that inverter based generation was dropping off line during the routine high speed clearing of transmission line faults. The purpose of this task force was to initially study the events of the Blue Cut Fire and subsequently the Canyon 2 Fire in southern California, and develop recommendations to minimize the future loss of inverter based generation. During this analysis, the task force identified a number of technical issues with PRC-024-2 that require clarification to help ensure inverter based generation contribute to the reliable operation of the bulk power system. These issues include:

a. Modifying the region outside the “No Trip” zone of the ride through curves to read “May Trip”, so that registered entities do not interpret this area as a must trip zone.

b. Clarifying the “Off Nominal Frequency Capability Curve” and the “Curve Data Point” tables on pages 8 and 9 of PRC-024-2 to reconcile the fact that the frequency capability curve starts at 0.1 sec, but the curve data point tables allows instantaneous (i.e. no deliberate time delay) operation.

Requested information
c. Clarifying the language in point #5 of the Curve Details found in the Voltage Ride-Through Curve Clarifications (page 11 of PRC-024-2) to eliminate confusion as to whether the curves pertain to RMS (Root Mean Square) or crest values. d. Making the language in point #1 of the Curve Details found in the Voltage Ride-Through Curve Clarifications (page 11 of PRC-024-2) regarding per unit voltage and nominal operating voltage as specified by the Transmission Planner internally consistent. e. Clarifying the use of cumulative time (point #3 of the Curve Details in the Voltage Ride-Through Curve Clarifications – Page 11 of PRC-024-2) beyond four seconds to clarify when cumulative values reset. This SAR proposes to address these technical issues.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-024-2 to address technical issues within the existing standard. The goal is to add clarity, eliminate inconsistency and address ambiguity in the existing requirements. An alternative approach would be to revise PRC-024-2 to incorporate the elements the CAISO is proposing to include in a new reliability standard.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows:: a. Update the PRC-024-2 ride-through curves to specify that the area outside the “No Trip” zone is a “May Trip” zone, so that it is not erroneously interpreted as a “Must Trip” zone b. Modify reliability standard PRC-024-2 so that its applies only to synchronous machines. The CAISO is also submitting a second SAR that proposes the development of a new standard for the minimum performance and operation of inverter based generation. As an alternative, existing PRC-024 can be expanded to include a new section that addresses the minimum performance requirements of inverter based generation. c. Clarify the Curve Data Point tables and the Off Nominal Frequency Capability Curves (pages 8 & 9) d. Clarify the language in point #5 of the Curve Details section of the “Voltage Ride-Through Curve Clarifications” on page 11. e. Clarify when this time starts and stops in relation to the four second cumulative timer.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The Standards Drafting Team should address the following technical issues within PRC-024-2: 1. The region outside the "No Trip" zone of the PRC-024-2 ride-through curves should be clearly marked as a "May Trip" zone so this region is not incorrectly interpreted as a "Must Trip" zone. Many newly interconnecting resources (including inverter based resources) on the BPS are setting voltage and protective functions based solely on these curves, since the area outside the no trip region is incorrectly interpreted as a must trip zone. The CAISO is in the process of obtaining control settings for various inverter based generators interconnected to the bulk power system, and notes that the majority of inverters were programmed to follow the curves exactly. This practice does not consider the capability of the resource to ride through transmission line faults. Clarification will help to ensure correct interpretation industry wide. This will enhance reliability since the generator owner will understand that the inverter protective settings should be based on equipment capability as opposed to following the curves in the standard, minimizing incorrect and undesired dropping of inverter based generation. 2. The "Off Nominal Frequency Capability Curve" (page 8 of PRC-024-2) is a logarithmic graph that starts at time t=0.1 seconds. However, the tables in the "Curve Data Point" section (pages 8 and 9 of PRC-024-2) allow for "instantaneous trip". Frequency cannot and should not be measured or calculated using an instantaneously sampled value. Frequency calculation methods use various types of time windows and filtering methods in order to accurately calculate grid frequency. Typically, these methods use a window on the order of 100 mSec (6 cycles). Thus, a delay of 100 mSec would occur even if the protective relay algorithm has no intentional time delay. This delay should be reflected in the standard. Also, the IRPTF identified that erroneous tripping due to frequency calculation errors was a significant factor in the Blue Cut Fire disturbance. http://www.nerc.com/pa/rrm/ea/Pages/1200-MW-Fault-Induced-Solar-Photovoltaic-Resource-Interruption-Disturbance-Report.aspx Eliminating instantaneous tripping for frequency disturbances reduces the probability of incorrect tripping due to spurious noise in the measure voltage, for example during the period of fault clearing. 3. Point #5 in the Curve Details section of the "Voltage Ride-Through Curve Clarifications" (page 11 of PRC-024-2) states, "voltages in the curve assume minimum fundamental frequency phase to ground or phase to phase voltage for the low duration curve and the greater of maximum RMS (Root Mean Square) or crest phase to phase voltage for the high voltage duration curve." There are a number of ways this can be interpreted.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information

To minimize the probability of incorrect tripping (as noted in point 2 above), any voltage compared with the PRC-024-2 voltage ride through curves should be a well-filtered, fundamental frequency component of the voltage waveform. This will filter out spurious voltage spikes caused by switching action on the BPS. Voltage protective relays should not operate at the voltage levels specified in the voltage ride-through curve using instantaneously sampled values. The other issue is that the overvoltage component of the clarification states, "the greater of maximum RMS or crest phase to phase voltage". The crest value is greater than the RMS value of a periodic waveform, so there is ambiguity regarding which value to apply. Without clarification, inverter based resources may trip based on different criteria. Failure to address this may lead to reliability issues, as identified in the Canyon 2 Fire disturbance analysis report. https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf

The clarification should focus on using the RMS value of the voltage, and that the voltage signal should be adequately filtered to obtain this fundamental component.

4. Point #1 of the Curve Details section of the "Voltage Ride-Through Curve Clarifications" on page 11 of PRC-024-2 states, "the per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES)." The Transmission Planner does not specify the nominal operating voltage. VAR-001-4 Requirement 5 requires each Transmission Operator to 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. The applicable entity should be modified to the Transmission Operator if nominal operating voltage is maintained. Transmission voltage schedules may change based on system conditions, e.g. season, time of day, etc.) and thus may not be static. Protective relay settings are not modified every time a voltage schedule changes. The per unit base for the curves should be based on the nominal voltage level to which the generator is connected at its Point of Interconnection. This is a static value and can be provided by the Transmission Planner.
5. The ride-through curves end at four seconds, and the curves use a cumulative time duration for the "No Trip" zone. Protective relays must be set to accommodate the cumulative nature of ride through curves. Under the current version of PRC-024-2, it is not clear at what point the cumulative values reset.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

This SAR proposes to clarify some issues and correct others. The cost impact to inverter based resources is minimal because it would only entail possibly reprogramming inverter protection set points.

Requested information
However, there is a significant benefit to the bulk power system in preventing incorrect tripping of inverter based generation.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Inverter based generation may be impacted by this proposed standard development. Inverter based generation often will use momentary cessation as a response to transient high or low voltage conditions. Inverters will momentarily cease to inject real or reactive current into the grid during momentary cessation. PRC-024 is silent on the topic of momentary cessation. It is not clear if momentary cessation for voltage excursions into the "No Trip" zone constitutes a violation of this standard. For this reason, this SAR proposes to make this standard applicable to synchronous machines. Further the CAISO is submitting a second SAR for the development of a new standard to provide minimum performance requirements for the operation of inverter based generation.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owners
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
Many of these proposals were developed by NERC's IRPTF and are outlined in the Blue Cut Fire and Canyon 2 Fire disturbance reports.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
CAISO is also submitting a SAR for the development of minimum operating performance criteria for inverter based generation.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC XXX-1 Inverter Based Resource Controls and Performance		
Date Submitted:	5/29/2018		
SAR Requester			
Name:	Keith E. Casey, Ph.D., Vice President, Market and Infrastructure Development		
Organization:	California Independent System Operator Corporation (CAISO)		
Telephone:	(916) 608-7125	Email:	kcasey@caiso.com

SAR Type (Check as many as apply)

- ☒ New Standard
- ☒ Revision to Existing Standard
- ☐ Add, Modify or Retire a Glossary Term
- ☐ Withdraw/retire an Existing Standard
- ☐ Imminent Action/ Confidential Issue (SPM Section 10)
- ☐ Variance development or revision
- ☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)

- ☐ Regulatory Initiation
- ☒ Emerging Risk (Reliability Issues Steering Committee) Identified
- ☐ Reliability Standard Development Plan
- ☐ NERC Standing Committee Identified
- ☐ Enhanced Periodic Review Initiated
- ☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

This SAR proposes a new controls based standard to ensure adequate performance of Bulk Electric System (BES) inverter based resources. This effort will ensure inverter based resources support reliable operation of the BES and have controls to provide essential reliability services. The CAISO is also submitting a complementary SAR to clarify and correct existing standard PRC-024. As an alternative approach, NERC could use the information submitted in this SAR to modify existing standard PRC-024.

The North American Bulk Power System (BPS) is undergoing a rapid evolution of the generating resource mix, predominantly driven by advancements in inverter technology, market economics and renewable portfolio standards. As the grid evolves and incorporates greater amounts of inverter based resources, NERC Reliability Standards must also evolve to set minimum performance requirements for inverter based BES resources. Without this action, BPS reliability will degrade and NERC's reliability program will lack the means to ensure that inverter based BES resources are providing necessary support to the BPS. To underscore this point, the CAISO notes that between August 2016 and May 2018, there have been at least 14 instances where inverter based solar generation incorrectly tripped and/or

Requested information

ceased to operate during the routine high speed clearing of BES transmission lines. The generation dropped varied from a low of 30 MW to a high of 1178 MW.

Inverter response to grid disturbances is predominantly driven by the logic programmed into the inverter and plant level controls of these non-synchronous resources. This is very different than the dynamic response of synchronous resources, which is predominantly driven by the physical nature of the machine. This fundamental difference between technologies unlocks new capabilities and flexibility for the BPS, and also presents challenges if performance is not sufficiently responsive to support BPS essential reliability services (ERS). NERC therefore needs to establish performance based requirements for control of inverter based resources. Recent grid events have demonstrated that the existing set of NERC Reliability Standards leaves potential reliability gaps, specifically related to the dynamic response of inverter based resources.

This concept is very similar to the performance based requirements set forth in the updated IEEE Std. 1547-2018, which revamped the requirements for distributed energy resources (DERs). That standard underwent a significant revision to improve the performance of future resources connecting to the distribution system, particularly as their penetration level continues to increase. The standard now identifies minimum requirements in the general performance specifications, reactive power capability, and voltage/power control requirements, response to abnormal grid conditions, power quality, islanding, and other aspects. It is not suggested that these requirements set for DERs should be used for BPS connected resources, nor should the NERC Reliability Standards attempt to set such stringent performance requirements for BES resources. However NERC should use this general approach to ensure that the inverter based resource's steady state and dynamic response characteristics support BPS reliability.

The Blue Cut Fire (https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf) and Canyon 2 Fire (900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report) disturbance reports identified a number of issues that are particular to the way inverter based resources perform when connected to the grid. Examples include the means for taking action on measured frequency and voltage waveforms, current injection during abnormal grid conditions, response times to provide current during dynamic events, fault current contribution and the use of momentary cessation.

The controls aspect of inverter based resources are very different than those used for synchronous machines. Inverter technology response is significantly faster and more flexible than synchronous generators, and most of the dynamic response of these resources is controlled by programmed logic in the inverter and plant level controls rather than the physical nature of the equipment. Statements that inverter based technology "should act like a synchronous machine" significantly underutilize the capabilities of inverter technology, and should not be the mindset moving forward. Rather, interconnections around the world have identified specific performance requirements for inverter based technology to ensure an adequate level of reliability. Controls-based performance requirements

Requested information
ensure features such as dynamic reactive power, automatic voltage control, and primary frequency response are provided in sufficient times and quantities to support the BPS. The North American grid should follow these examples in defining performance requirements for the control and dynamic performance of inverter based technology. This is not a hindrance to this technology, but rather guidance that manufacturers are seeking so they can design the equipment to reliably meet minimum performance specifications and simultaneously compete on a level playing field. NERC should review the performance requirements from other grids around the world and establish similar requirements. This SAR proposes a new NERC Standard that sets performance requirements for inverter based resources with a focus on the controls and dynamic performance of these resources. Without a continent-wide performance-based NERC Standard, regional requirements may lead to disparate interconnection requirements that may not align with each other interconnection-wide. This could potentially lead to further reliability gaps in the future. The NERC IRPTF (Inverter based Resource Performance Task Force) is developing a Reliability Guideline for Inverter Based Performance. This guideline should serve as the cornerstone for any future standard, since the recommended performance specifications in that guideline will be industry vetted across a wide group of experts including: Original Equipment Manufacturers (OEMs), Generator Owners, Generator Operators, Transmission Planners, Planning Coordinators, Balancing Authorities, Reliability Coordinators, and other industry experts. It should be noted that Guidelines are neither compulsory nor enforceable.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes a new controls based standard to ensure adequate performance of BES inverter based resources. Purpose: Develop a new NERC Reliability Standard that specifically addresses inverter based resource controls and performance aspects as specifically identified in recent disturbance event analyses, NERC Advisories, and the NERC IRPTF Guideline.
Project Scope (Define the parameters of the proposed project):
The scope is to develop a new NERC Reliability Standard for inverter based resources that establishes minimum performance requirements, including controls and dynamic performance, and to address recommendations in the Blue Canyon Fire and Canyon 2 event analyses, and associated NERC Advisories (NERC Alerts).

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
A new NERC Reliability Standard to address the controls and dynamic performance aspects of inverter based resources should include, at a minimum, the elements listed below. These have been discussed thoroughly by the NERC IRPTF, and have been factors in recent grid disturbance events as well as potential future performance issues. 1. Many BES inverter based resources use a form of "ride through" where they cease injection of current into the BPS for off nominal voltages. This mode of operation is often referred to as momentary cessation. Both the Blue Cut Fire (https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf) and Canyon 2 Fire (900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report) disturbances identified this control mode as a contributing factor to the loss of BPS connected inverter based resources following short circuit fault events on the grid. This performance does not support interconnection wide grid stability during low voltage transients, and should not be allowed moving forward. NERC IRPTF simulations demonstrate that this performance may lead to wide scale system instability. Existing inverter based resources may not be able to feasibly eliminate its use, and there are legitimate equipment limitations that preclude inverters from using a more grid supportive form of ride through. This should be considered by the Standard Drafting Team when crafting requirements. However, new inverter based resources are designed for current injection during "ride through" conditions and should not use momentary cessation. The topic of momentary cessation and recommendations to reduce its impact is discussed in NERC's Industry Recommendation dated May 1, 2018. https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf Again, NERC Alerts are neither compulsory nor enforceable. 2. The response of an inverter based resource is predominantly driven by the logic programmed into the controls of the overall facility, including the individual inverters and the plant level control system. Inverters are current source devices, and therefore performance should be specified as to the type of current (real or reactive component) to be injected. Performance requirements should be developed that ensure that these resources inject an adequate level of grid supportive current during abnormal grid conditions (off nominal voltage and/or frequency).

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
a. Active current or frequency performance requirements should be established to ensure that the capability to provide primary frequency response is available if needed by the Balancing Authority, consistent with technical specification of FERC Order No. 842. b. Reactive current or voltage characteristics should be specified to ensure that local and wide area voltage support is provided, as expected, from generating resources. c. Response to large disturbance events such as faults should be specified to ensure that fault current is provided in a timely manner from inverter based resources. Controls are often tuned for each individual connection to the BPS; however minimum performance requirements should be set to ensure adequate fault current and a stable recovery following fault clearing. Other grid codes around the world have begun specifying these characteristics, particularly as the penetration of these resources continues to grow. d. Any performance requirements should not limit inverter technology from exploring different solution options; however they should set minimum performance characteristics that may be met in multiple ways. e. Refer to the NERC IRPTF Reliability Guideline on Inverter Based Resource Performance for more details. This guideline should be used as the cornerstone for future standard requirements. 3. Other aspects that typically are not a significant focus for synchronous machines should also be considered from a performance specification standpoint. These include automatic reconnection, ability to respond to ramp rate limits and automatic generation control signals (dispatch ability), diagnostic equipment, and other aspects that ensure grid operators have the tools and capabilities available to maintain reliability.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Due to a lack of any standard addressing the minimum performance of inverter based generation connected to the BES, Original Equipment Manufacturers (OEM)s often apply standards for resources connected to the distribution system to BES resources. Development of a national standard will foster robust competition which will lead to greater cost control, along with improved BPS reliability.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
This SAR proposes development of a standard applicable to *inverter based generation resources that will interconnect to the BES.*
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owners

Requested information
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
PRC - 024
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives. The NERC IRPTF will issue a Guideline. However the Guideline is neither mandatory nor enforceable, and therefore is not adequate to maintain or promote BES reliability.

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

Market Interface Principles	
Does the proposed standard development project 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

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Project 2018-01 Canadian-specific Revisions to TPL-007-2

Update

Regional Standards Committee
August 2018

Timelines

Proposed Timeline for Project 2018-01 Canadian-specific Revisions to TPL-007-02		
Anticipated Date	Location	Event
March 30, 2018	-	SAR to SC for approval and to authorize solicitation of nominations for SAR DT
May 25, 2018	-	SC Appoints the SAR DT
May 25, 2018	WebEx	SAR DT Meeting
June 13, 2018	-	Submit Updated SAR to SC for Approval; SC Appoints SAR DT as the Standard Drafting Team
July 26, 2018	-	SDT Meeting via WebEx to Discuss Potential Approaches
July 31 – August 1, 2018	HydroQuébec Montreal, QC	Drafting Team Meeting
August 8, 2018	WebEx	Drafting Team Meeting
August 9, 2018	-	Documents due for Informal Posting
August 10 – September 6, 2018	-	**Informal Posting**
September 11 – 12, 2018	Toronto (HydroOne)	Drafting Team Meeting
September 12, 2018	WebEx	Potential Webinar
September 17, 2018	-	Pens Down | Initial Ballot
September 18 – 24, 2018	-	Quality Review | Initial Ballot
September 26, 2018	-	Submit Docs to Standards Committee | Initial Ballot
October 2, 2018	-	Standards Committee Special Call
October 5 – November 21, 2018	-	Initial Ballot and Comment Period
October 9, 2018	WebEx	Potential Webinar
November 27 – 28, 2018	Ontario (TBD)	Drafting Team Meeting
November 29 – December 5, 2018	-	Quality Review | Additional Ballot
December, 6 2018 – January 22, 2019	-	Additional Ballot and Comment Period
January 23, 2019	WebEx	Drafting Team Meeting
January 24 – February 2, 2019	-	Final Ballot
February 7, 2018	-	NERC Board Meeting

Canadian-specific Revisions

Attachment 1-CAN

- Variance to allow Canadian entities define 1-in-100 year GMD planning event using additional data sets. Such data:
  - Can be used to develop detailed models and analysis techniques that more accurately characterize the region-specific parameters; and
  - May include geomagnetic field (based on magnetometers) and earth conductivity information. In some cases, direct GIC measurements are also available to help validate modeling and simulation results.
- Attachment 1-CAN provides an approach for using such data, where available, to conduct GMD Vulnerability Assessment(s). Where the information available is insufficient to support an alternative approach, Canadian registered entities should use the methodology in Attachment 1.

Variance to Requirement R7

- Variance to recognize that implementation of Corrective Action Plan is subject to regulatory approval by the regulators in Canadian jurisdiction.

Informal Comment Period

Posting

- The proposed variance is posted for a 28-day informal comments period open through September 6, 2018.

- Entities from both Canada and the United States are encouraged to submit their comments.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-45**

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~~

5. Effective Date: See Implementation Plan.

B. Requirements and Measures

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~~032 standard, 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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with ~~a~~ the selected known outage(s); and

~~**1.1.1.1.**~~**1.1.2.2.** Does not exclude known outage(s) solely based upon the outage duration ~~of at least six months.~~ .

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**1.1.6.** Resources (supply or demand side) required for Load.

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-032 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.

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 expected to produce more severe System impacts on its portion of the BES, 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~~assessed. The ~~studies~~analysis 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. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.

~~**2.4.3.**~~**2.4.4.** 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.

~~2.4.4.~~**2.4.5.** 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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~~ Remedial Action Schemes.
- 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.

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.

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.

~~**M1.**~~**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.

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~~Remedial Action Scheme 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. 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.

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.~~

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.

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]*

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.

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]*

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.

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]*

~~**M2.**~~**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.

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.

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.

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 applicable entity shall keep data identified in Measures M1 through M8 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.

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.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	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~~032 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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 P~~7~~8) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	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 P~~7~~8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P~~7~~8) in Table 1. 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 P~~7~~8) in Table 1. OR	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 P~~7~~8) in Table 1. OR	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 P~~7~~8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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 Contingency analysis as described in Requirement R4, Part 4.3.	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.
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	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

D. Regional Variances

None.

E. Associated Documents

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	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability~~:~~ (P0 through P8 events):

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~~:~~ (P0 through P7 events 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~~:~~ (P1 through P7 events 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

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~component of a Protection System[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

P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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	3Ø	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.

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

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.	

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.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

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~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows:

    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;

    c. A single station dc supply associated with protective functions ~~or types: pilot (#85), distance (#21), differential (#87), current (#50, 51~~required for Normal Clearing, and ~~67),~~that single station dc supply is not monitored or not reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67),~~ and ~~tripping (#86, & 94).~~open circuit;

    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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

M3. 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.

M4.M1. 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.

M5. 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.

M6.M1. 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.

M7.M1. 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.

M8. 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.

M9. 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.

M10.M1. 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 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.	the categories (P2 through P7) in 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

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~related need who requested the Planning Assessment in writing.~~

E.A. 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	

Version	Date	Action	Change Tracking
		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.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-5**

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: See Implementation Plan.**

B. Requirements and Measures

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-032 standard, 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) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities.

~~1.1.3.~~1.1.4. Real and reactive Load forecasts.

~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange.

~~1.1.5.~~1.1.6. Resources (supply or demand side) required for Load.

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-032 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.

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 expected to produce more severe System impacts on its portion of the BES, 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 assessed. The analysis 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. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.

2.4.4. 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.

2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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 Remedial Action Schemes.
- 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.

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.

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.

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.

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 Remedial Action Scheme 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. 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.

~~**4.2.1.** If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

~~**4.2.2.** If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:~~

~~**4.2.2.1.** List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.~~

~~**4.2.2.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~

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.~~

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

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 applicable entity shall keep data identified in Measures M1 through M8 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.

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.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	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-032 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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 P8~~7~~) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	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 P8~~7~~) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P8~~7~~) in Table 1. 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 P8~~7~~) in Table 1. OR	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 P8~~7~~) in Table 1. OR	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 P8~~7~~) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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 Contingency analysis as described in Requirement R4, Part 4.3.	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.
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	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

D. Regional Variances

None.

E. Associated Documents

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	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability (P0 through P8 events):

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 (P0 through P7 events 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 (P1 through P7 events 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

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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	3Ø	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.

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] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   ~~d.~~ 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. ~~3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~
   ~~e. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~

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.	~~f. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~ ~~g.~~d. ~~3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Cleari~~ ~~h.~~e. 3Ø internal breaker fault. ~~i.~~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.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

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. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-5**

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: See Implementation Plan.**

B. Requirements and Measures

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-032 standard, 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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

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.

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-032 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.

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 expected to produce more severe System impacts on its portion of the BES, 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 assessed. The analysis 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. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.

2.4.4. 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.

2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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 Remedial Action Schemes.
- 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.

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.

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.

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.

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 Remedial Action Scheme 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. 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.

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

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

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 applicable entity shall keep data identified in Measures M1 through M8 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.

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.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	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-032 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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 P8) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	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 P8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P8) in Table 1. 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 P8) in Table 1. OR	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 P8) in Table 1. OR	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 P8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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 Contingency analysis as described in Requirement R4, Part 4.3.	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.
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	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

D. Regional Variances

None.

E. Associated Documents

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	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability (P0 through P8 events):

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 (P0 through P7 events 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 (P1 through P7 events 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

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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	3Ø	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.

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] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] 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

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.	

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.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

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. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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.

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Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Current Option (Draft 3):

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known ~~-~~outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**1.1.6.** Resources (supply or demand side) required for Load.

Option considered for Draft 3:

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. ~~These~~ This outage coordination~~s are~~ is required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Previous Option (Draft 2)

1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The SDT did not feel like a time duration alone would capture "significant outages". Additionally, the language allows PC's to develop a process for selecting "significant outages" to be studied in the Near-Term Transmission Planning Horizon.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure13" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure13" with "a component failure of a Protection System13."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Revision By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and

- Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.

- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language.

Current Option Footnote 13 (Draft 3)

1. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
   - A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
   - A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
   - A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
   - A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Previous Option Footnote 13 (Draft 2)

The previous option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team added clarifications to the previous draft option which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

Extreme Events and P8 Category:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754, Section 1600 data collection and report indicated a risk to the BES for three phase faults followed by single points of failure of a protection system. Therefore, the SDT decided to make Category P8 planning event if a three-phase fault following by a single points of failure resulted in Cascading or instability.

Revision By Standard Drafting Team to Satisfy FERC Order

Current Option (Draft 3):

~~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. 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.

4.2.1. ~~If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

~~4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:~~

~~4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementationList System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~

~~4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~

Previous Option (Draft 2):

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.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

Standard Drafting Team Proposal

The standard drafting team feels that there is a reliability risk to the BES if Cascading or instability results in a three-phase fault followed by single point of failure of a protection system. There was confusion in the industry with the language that was similar to a CAP but not exactly a CAP. Therefore, the standard drafting team decided to create a P8 planning event which required a CAP if Cascading or instability occurs.

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Implementation Plan

Project 2015-10 Single Points of Failure

Reliability Standard TPL-001-5

Applicable Standard(s)

- TPL-001-5 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Prerequisite Standard(s)

- None

Applicable Entities

- Planning Coordinator
- Transmission Planner

Background

Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754 issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee September 2015 report titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4~~; and~~, relating to:
    - modeling known outages with a duration of less than six months; and
    - adding stability analysis for the outage of major Transmission Equipment with a lead time of one year or more.
- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations

~~The 36-month~~This implementation ~~period for TPL-001-5~~plan provides 36 months until the effective date of the Standard, providing Planning Coordinators and Transmission Planners with time to update their annual Planning Assessments to include the new System models and studies required by the standard. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time to develop, among other things:

- A ~~process~~procedure or technical rationale for ~~coordinating with the Reliability Coordinator which~~selecting known outages of generation ~~of~~and Transmission Facilities~~ of less than six months shall be represented in planning studies~~;
- A process for establishing coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional base case models and analysis.

In addition, ~~the~~this implementation plan includes an additional 24~~-~~-month period for the development of Corrective Action Plans (CAPs) under TPL-001-5 to address newly-added studies for P5 and P8 planning events involving single points of failure on Protection Systems.

This extended implementation period for the part of Requirement R2, Part 2.7 that states: "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", acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed.

This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time beyond that provided to conduct the new studies and analysis to develop processes for coordination with asset owners and protection engineers to identify appropriate ~~Corrective Action Plan~~CAP actions and establish the associated timetables for completion. This includes~~:~~

- ~~Any~~ any necessary ~~Corrective Action Plans to address Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any necessary Corrective Action Plans~~CAP to address System performance issues for studies involving Table 1 Category P5 and P8 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2, Part 2.7 for the ~~following~~ non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13~~, items 2-4:~~.

- ~~A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported~~

- ~~A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit~~
- ~~A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.~~

Lastly, the provisions related to ~~Corrective Action Plans~~CAP including Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) are carried forward from the TPL-001-4 implementation plan.

Effective Date

TPL-001-5 – Transmission System Planning Performance Requirements

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 36 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided 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 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for TPL-001-5 Requirement ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items ~~2, 3,~~b, c, and d and ~~4~~P8

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

Entitles shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items ~~2, 3~~b, c, and ~~4~~d or P8 until 24 months after the effective date of Reliability Standard TPL-001-5.

~~Note Regarding Corrective Action Plans~~

For CAPs developed to address failures to meet Table 1 performance requirements for P5 or P8 events only, Transmission Planners and Planning Coordinators shall not be required to comply with the section of Requirement R2, Part 2.7 that states: "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**", until 96 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding CAPs

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval of TPL-001-4, 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~~CAP applying to the following categories of Contingencies and events identified in TPL-001-5, 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-001-5:

- 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)

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment without CAPs for revised P5 or P8 in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall ~~complete~~develop any required ~~Corrective Action Plans~~CAP under ~~Requirement R4, Part 4.6 and~~ Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items ~~2, 3~~b, c, and ~~4~~d and P8 by 24 months after the effective date of Reliability Standard TPL-001-5.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

February 2018

RELIABILITY | ACCOUNTABILITY

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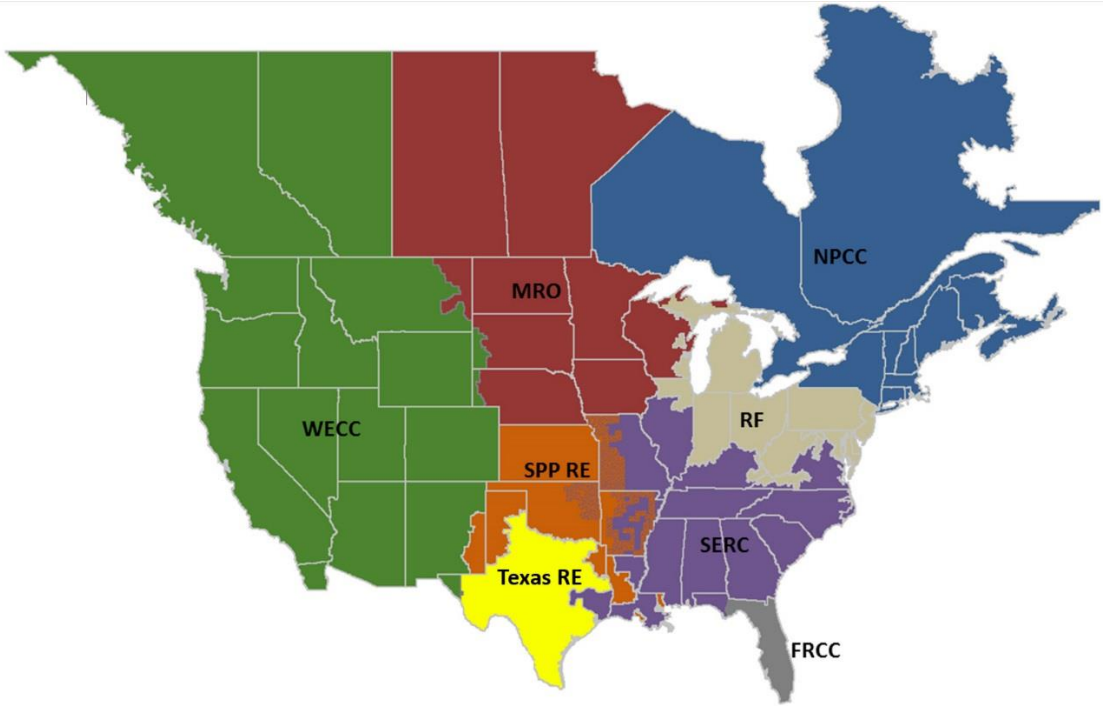
Table of Contents

Preface iii
Executive Summary iv
Key Concepts of FERC Order No. 754 iv
Key Concepts of FERC Order No. 786 iv
Summary of proposed revisions: iv
Introduction 1
Background 1
FERC Order No. 754 1
FERC Order No. 786 1
Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754) 1
NERC Advisory 1
FERC Order No. 754 1
FERC Technical Conference 1
Joint SPCS-SAMS Report 1
Revisions to TPL-001-4 2
Table 1-Footnote 13 2
The Distinction Between Category P4 and Category P5/P8 Planning Events 5
Single Points of Failure – Category P5 and P8 Planning Events 5
Requirement R4 Parts 4.2 and 4.5 6
Section 2: FERC Order No. 786 Directives 7
Background 7
Order No. 786 P. 40: Maintenance outages in the Planning Horizon 7
NERC SAMS Whitepaper Recommendations 7
Revisions to TPL-001-4 8
Requirement R1 Part 1.1.2 8
Requirements R2 Part 2.1.3 and Part 2.4.3 8
Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment 8
NERC SAMS Whitepaper Recommendations 9
Revisions to TPL-001-4 10
Requirement R2 Part 2.4.5 10
Section 3: Applicability 11

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

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standards Development Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Proposed revisions to "Table 1 – Steady State and Stability Performance Planning Events", adds a new P8 Planning Event to include a 3-phase fault and failure of a non-redundant component of a Protection System. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 and the proposed new Category P8 Planning Events.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, Category P3 and P6 do not sufficiently cover planned maintenance outages, and Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration and replace it with the requirement to document an established procedure or the technical rationale, to determine which known outages to study.. Proposed revisions includes stability study for long lead equipment that does not have a spare.

Summary of proposed revisions:

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Modified how known outages are selected for study.
- Requirement R2, Part 2.1.3 – Added model conditions for steady state analysis of P1 events for known outages.
- Requirement R2, Part 2.4.3 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Note the Steady State and Stability performance thresholds that are applicable to Category P1 through P7 events only and not to P8 events

- Table 1 – Added Category P8 event to include SPF following a 3-phase fault, with applicable performance thresholds
- Table 1 – Modified Footnote 13 to specify SPF.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with single points of failure (SPF) in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF. Available

FERC Order No. 786

In Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the Technical Conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC PC/OC, summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action. To address this risk, the SPCS and the SAMS

[3] *See Industry Advisory: Single Point of Failure*
http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf

considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 standard drafting team are summarized in the following section.

Revisions to TPL-001-4

Table 1-Footnote 13

The SPCS/SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Based on discussion and industry comment, the SDT proposes similar revisions to Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the drafting team sought to limit the scope of Footnote 13, item 1 with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. An SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the drafting team did not include backup protective relays in the scope of Footnote 13, item 1 given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The drafting team recognizes that Bulk Electric System (BES) Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond

to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault, and P8 event, for a 3-phase fault, in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as P5 and P8 events.

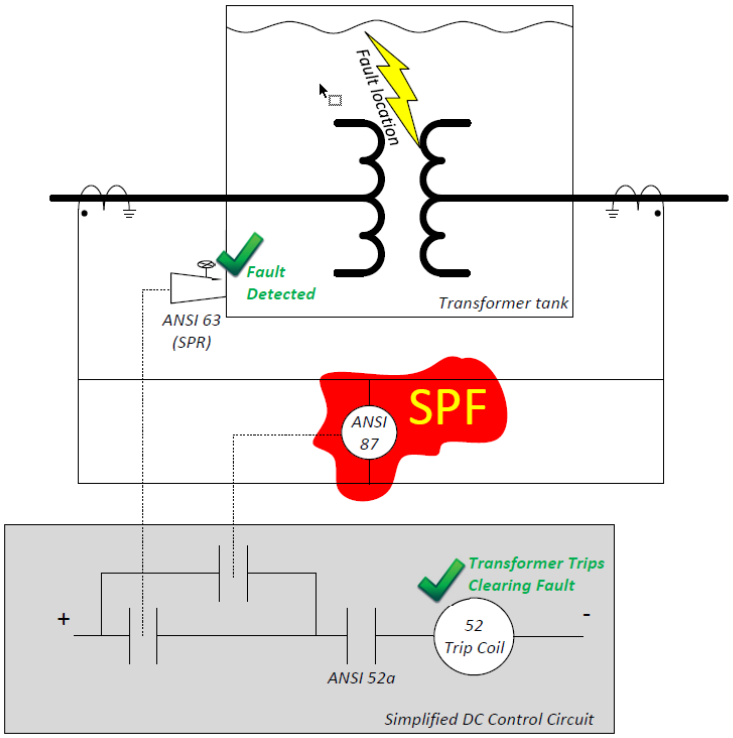


Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

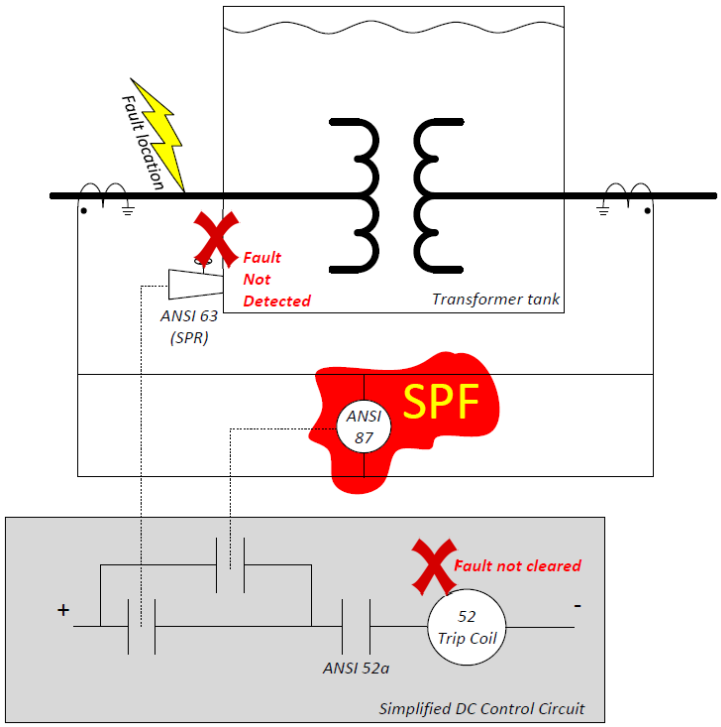


Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the Bulk Electric System can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

The drafting team adopted the fundamental principles of the SAMS/SPCS recommendations regarding station protection system DC supply. Failure of a single station protection system DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The drafting team partly modified the SAMS/SPCS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13, item c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt

notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit Therefore, this requirement may be more applicable to legacy systems.

The Distinction Between Category P4 and Category P5/P8 Planning Events

"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 and P8 Planning Events. The sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 and P8 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed Clearing associated with circuit breaker failure.

Single Points of Failure – Category P5 and P8 Planning Events

Analysis of the data collected under the Order No. 754 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant action. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to unacceptable system performance if a Protection System component SPF exists).

The drafting team has modified Table 1, Footnote 13 to capture the SAMS/SPCS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified single points of failure of concern.

Proposed revisions to "Table 1 – Steady State and Stability Performance Planning Events", adds a new P8 Planning Event to include a 3-phase fault and failure of a non-redundant component of a Protection System. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 and the proposed new Category P8 Planning Events

Given the risk to BES reliability raised at the FERC Technical Conference in conjunction with the SAMS/SPCS recommendations, the drafting team considered the manner in which additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. While events initiated by a three-phase fault are less probable than events initiated by a single-phase-to-ground faults, single-phase-to-ground faults with Delayed Clearing, particularly associated with the non-redundant components of a Protection System enumerated in Table 1, Footnote 13, can often evolve into three-phase faults, leading to system performance which is more severe than for the Table 1, P5 event. To address this concern (the study of Protection System SPF with a three-phase fault), the drafting team has developed a new P8 Planning Event; however, unlike the Category P1-P7 Planning Events, a Corrective Action Plan is only required if the P8 event results in Cascading. Accepting more severe system performance is seen as a reasonable balance with the lower likelihood, but reasonable risk, of the SPF with a three-phase fault. Table 1, Footnote 13 also provides the attributes of the specific non-redundant Protection System components that the entity shall consider for evaluation for the P5 and P8 events.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 and P8 Planning Events will likely be to add Protection System component redundancy, consistent with the components enumerated in Footnote 13. Protection System redundancy changes to address P5 concerns should also reduce or even negate non-redundant components that need to be considered in P8 events; hence, potentially mitigating many P8 concerns.

The P5 event steady-state analysis should also be valid and representative of P8 events. It should be noted that the addition of the P8 event will only add the need for additional stability analysis.

Requirement R4 Parts 4.2 and 4.5

The drafting team proposes non-substantive editorial changes to combine part of Requirement R4, Part 4.5 with Requirement R4, Part 4.2. The rearrangement of Requirement 4, Parts 4.2 and 4.5 were done to improve consistency within the Standard and do not create any new requirements. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable low-cost, cost-effective measures to lessen the risk or severity of these events.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

Order No. 786 P. 40: Maintenance outages in the Planning Horizon

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. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing "with duration of at least six months" and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an "academic exercise" due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

Revisions to TPL-001-4

Requirement R1 Part 1.1.2

The drafting team gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the TP or PC.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective "one size fits all" means of addressing the FERC directive. However, FERC's Order 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available.

The drafting team modified Requirement R1, Part 1.1.2 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that TPs and PCs currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be studied.

It is only necessary to consider known outages expected to result in Non-Consequential Load Loss for P1 event in Table 1. This allows the PC and TP to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary modeling of outages which the PC and TP do not expect to be a problem.

Consistent with the intention of Order No. 786, the drafting team included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be modeled.

The PC and TP must have documented either an established procedure or technical rationale for the determination of which known outages may be excluded from modeling. The established procedure is intended to include consultation with the affected Reliability Coordinator, consultation with outage Transmission and/or Generator Owner(s), or application of established outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination.

This proposed modification is for consideration of known outages beyond the Operations Planning time horizon.

Requirements R2 Part 2.1.3 and Part 2.4.3

Consistent with FERC's directive, the drafting team modified Requirements **R2 Parts** 2.1.3 and 2.4.3 to further recognize the intent to limit required study to only those known outages that are expected to produce severe System impacts on the PC/TP's respective portion of the BES.

Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.

- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2 Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 standard drafting team revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning and protection engineers that will need to conduct the studies and submit the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines.

Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant Protection System component could result in a potential reliability risk. These entities must provide this information, as well as resulting fault clearing times, to Transmission Planners for proper study.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2015-10 Single Points of Failure TPL-001

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Requirement R4 in Project 2015-10 and Single Points of Failure TPL-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

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 Justification for TPL-001-5, Requirement R1

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R1

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R2

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R2

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R3

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R3

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R4

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R4

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R5
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R5
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R6
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R6
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R7
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R7
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R8
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R8
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

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Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **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. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **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-032 standard, 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.	Requirement R1 body. Updated referenced standard number in body of requirement. Requirement R1 Part 1.1.2 Consistent with FERC Order 786 Para 40, the six-month threshold that could exclude planned maintenance outages is eliminated. Additionally, the addition of Near-term Planning Horizon aligns this requirement with IRO-017-1 Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	**1.1.2.** Known ~~-~~outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum: ~~**1.1.2.1.** for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events	Assessment for the Near-Term Transmission Planning Horizon. Requirement R1 Parts 1.1.2.1, 1.1.2.2, and 1.1.2.3 Substantial regional differences exist for outage coordination methods and procedures, making it difficult to define specific known outage selection criteria pertinent to all. Therefore, considering the NERC SAMS recommendations, selection of known outages in the Near-Term Planning Horizon were limited to three primary considerations. Requirement R1 Part 1.1.2.1 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss (FERC Order 786, Paragraph 41).

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	in Table 1 when concurrent with the selected known outage(s); and ~~1.1.2.2.~~ Does not exclude known outage(s) solely based upon the outage duration. ~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities. ~~1.1.3.~~1.1.4. Real and reactive Load forecasts. ~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange. ~~1.1.5.~~1.1.6. Resources (supply or demand side) required for Load.	Therefore, System models shall represent known outages in the Near-Term Transmission Planning Horizon that are expected to result in Non-Consequential Load Loss following a Table 1 P1 Event. It is noted that the performance requirements for all Table 1 Events include that the System shall remain stable, as well as Cascading and uncontrolled islanding shall not occur. Requirement R1 Part 1.1.2.2 Planned outages lasting less than six months could be overlooked when the Transmission Planner and Planning Coordinator formulate System models (FERC Order 786, Paragraph 42). Further, there is no correlation between the System impact of an outage and its duration. Therefore, while duration is an

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		acceptable factor to consider when selecting a known outage for representation in System models, the duration shall not be the sole factor for omission. <u>Requirement R1 Part 1.1.2.3</u> A technical rationale is necessary to establish a rules-based approach to the selection of known outages for representation in System models. Similarly, regional operational approaches and outage coordination procedures vary, but the selection of known outages should incorporate input from operational experience. Therefore, known outages shall be selected according to an established procedure or a technical rationale.
TPL-001-4, Requirement R2	TPL-001-5, Requirement R2	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	
TPL-001-4, Requirement R2 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.	TPL-001-5, Requirement R2 2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.	Requirement R2 Part 2.1.3 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
TPL-001-4, Requirement R2 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.	TPL-001-4, Requirement R2 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.	TPL-001-5, Requirement R2, Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	
	TPL-001-5, Requirement R2 2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.	TPL-001-5, Requirement R2, Part 2.4.3 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.3. For reasons similar to those justifying changes to Requirement R2 Part 2.1.3, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		the BES to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
	TPL-001-5, Requirement R2 2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.	<u>TPL-001-5, Requirement R2, Part 2.4.5</u> Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.
TPL-001-4, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for	TPL-001-5, Requirement R3 **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	No Modification Made

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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:	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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. 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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	mitigate the consequences and adverse impacts of the event(s) shall be conducted.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
included in the Contingency list. 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.		
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R4 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.	TPL-001-5, Requirement R4, **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 Remedial Action Scheme is not	<u>TPL-001-5, Requirement R4, Part 4.2</u> Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. If the analysis concludes there	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. ~~**4.2.1.** If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~ ~~**4.2.2.** If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible~~	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~actions designed to prevent the System from Cascading shall:~~ ~~**4.2.2.1.** List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.~~ ~~**4.2.2.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~ **4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.~~	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

NERC
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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1.1 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	David Lemmons – Chair of the Project 2017-01 BAL3 SAR Drafting Team		
Organization:	Project 2017-01 BAL3 SAR Drafting Team		
Telephone:	303.807.7949	Email:	David.Lemmons@ethosenergygroup.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The revisions to this standard are proposed to be approached in phases; however, the Standard Drafting Team (SDT) will determine the priority for each of the specific tasks. The revisions proposed in ~~the first~~ ~~p~~Phase I are intended only to correct inconsistencies identified through ~~use~~ implementation of the standard and to improve efficiencies and effectiveness of the administration associated with the standard. Revisions proposed for ~~the~~ ~~second~~ Phase II are modifications intended to align the standard more closely with its purpose.

SAR Information

Phase I

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions, as well as process inefficiencies, have been identified. It is expected that as Frequency Response improves, the approaches embedded in the standard for annual samples may need to be modified.

~~In addition to fixing the inconsistencies outlined below, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval.~~

The items that need to be addressed are to:

- Revise the IFRO calculation in BAL-003-1 due to issues identified in the 2016 Frequency Response Annual Analysis (FRAA) Report, such as the IFRO values with respect to Point C and varying Value B;
- Reevaluate the interconnections' Resource Contingency Protection Criteria;
- Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12);
- Review and modify as necessary Attachment A of the Reliability Standard to remove administrative tasks and provide additional clarity, e.g., related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and
- Make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.

In addition to fixing the inconsistencies outlined above, the SDT may separate the administrative and procedural items and propose that they be reassigned to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval.

Phase II

The intent of the Reliability Standard is to ensure sufficient Frequency Response for each interconnection. Allocation of the responsibility to provide Frequency Response needs to reflect current conditions of the grid and correspond~~be commensurate~~ with the entities which provide and/or coordinate its provision.

- Both the IFRO calculations and the allocation of IFROs to reliability entities are retrospective (up to 2 years). The review should determine if there are alternate methodologies which consider

SAR Information
characteristics affecting Frequency Response (e.g., load response, mix and type of generation, Balancing Authority Area (BAA) footprint changes) to make allocation as equitable as possible; • Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response); and • Review the measurement methodology of Frequency Response (both System and equipment level): o The Frequency Response Measure (FRM) should be reviewed to ensure that over-performance by one entity does not negatively impact the evaluation of performance by another.
Purpose or Goal (How does this request propose to address the problem described above?):
Phase I Review and revise the BAL-003-1.1 Reliability Standard and process documents to address the items listed in Phase I above. Additionally, the SDT should consider removing the supporting procedural and administrative processes from Attachment A ~~shall be considered~~ for incorporation into ERO-approved reference document(s) such that timely process improvements can be made as future lessons are learned. For additional information, please refer to the 2016 FRAA Report. **Phase II** Review and revise the BAL-003-1.1 Reliability Standard subsequent to Phase I and process documents to address the items listed in Phase II above.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To address the issues with the Reliability Standard referenced above, including those that were described in the 2016 FRAA Report.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Phase I During the 2016 annual evaluation of the values used in the calculation of the IFRO, the above-mentioned issues listed under Phase I were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection

SAR Information
Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarify language in Attachment A, and (5) make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report. **Phase II** The scope of the work will be to (1) revise the Reliability Standard to address the Real-time aspects of Frequency Response necessary to maintain reliability, (2) ensure comparability of and applicability to the appropriate responsible entities, (3) develop measurements to incorporate Real-time and resource and load characteristics, and (4) ensure equitability of performance measurement.
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.)
Phase I Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 1 of Phase I above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. According to the FRAA Report, this ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved recovery performance. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 2 of Phase I above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years," which is the August 4, 2007 event. The ~~standard drafting team~~SDT should revisit this issue for modifications to the BAL-003-1 Reliability Standard, and the Resources Subcommittee (RS) should recommend ~~how~~ the criteria used to identify events ~~are selected~~ for each interconnection. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 3 of Phase I above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a

SAR Information
frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds) and may be the value known as Point C' which typically occurs in the 72 to 95 second range after t_0. Consider revising BAL-003-1.1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 5 of Phase I above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data. **Phase II** Consider revising the BAL-003-1.1 Reliability Standard to: • Make the IFRO calculations and associated allocations 1) ~~be~~ more reflective of current conditions, 2) consider all characteristics affecting Frequency Response (e.g., load response, mix and type of generation), 3) include all applicable entities, and 4) be as equitable as possible; and • Make the FRM 1) ensure that over-performance by one entity does not negatively impact the evaluation of performance by another, 2) measure types/periods of response in addition to secondary Frequency Response, particularly primary Frequency Response, 3) include all applicable entities, and 4) make allocations as equitable as possible.

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

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.		Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.		Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.		Yes

Related Standards	
Standard No.	Explanation
MOD-027-1	This standard applies to GOPs and requires verification of Turbine/Governor and Load Control or Active Power/Frequency Control Functions. Modifications to the BAL-003-1.1 Reliability Standard will need to coordinate with/complement MOD-027-1 to ensure there is no overlap or gap of requirements for governor performance.
EOP-005-2	Consider impacts to EOP-005-2.
BAL-001-TRE-1	Consider impacts to BAL-001-TRE-1.

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.

Regional Variances	
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

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Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

STD	Standard Reference	Comment / Proposed Action
BAL standards		No Action Required
CIP standards		
CIP-002-5.1a	Attachment 1: 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. After retirement of FAC-10-3, PCs and TPs will no longer be required to establish IROLs using FAC-010-3; however, IROLs will continue to be required to be established by the RC. Similar to Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a, FAC-014-3, Requirement R6, requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the Generator Owners (GO) and Transmission Owners (TOs). FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a

		list of Facilities owned by that entity that are critical to the derivation of the IROL." While Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modify Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise Requirement R2, Part 2.6 of Attachment 1 in response to the retirement of FAC-010-3 to eliminate PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's

		Planning Assessment for the Near-Term Transmission Planning Horizon.
CIP-014-2	Applicability 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the PC and TP (and RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. Similar to 4.1.1.3 of the Applicability section of CIP-014-2, FAC-014-3, Requirement R6 requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the GOs and TOs. FAC-014-3 Requirement R6 specifically states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." While 4.1.1.3 of the Applicability section of CIP-014-2 could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modifying 4.1.1.3 of the Applicability section of CIP-014-2 to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in

		the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise 4.1.1.3 of the Applicability section of CIP-014-2 in response to the retirement of FAC-010-3 to eliminate the PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
COM standards		No Action Required
EOP standards		No Action Required
FAC standards		
FAC-003-4	**Introduction:** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	The Applicability section of the Introduction specifies "applicable lines" and includes overhead transmission lines (< 200 kV) identified as an element of an IROL by the PC. Requirements R1 and R2 reference "applicable lines" and IROLs as well. "Applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. All overhead transmission lines that operate at 200 kV and above are included as "applicable

	Requirements **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below… **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	lines" (4.2.1). Qualifications are then being made to include < 200 kV transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management. The retirement of FAC-010 does not create a reliability gap here. The language in Parts 4.2.2 and 4.3.1.2 of FAC-003-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-014; however, IROLs are required to be established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." FAC-003-4 is applicable to GOs and TOs. Accordingly, these entities are made aware of IROLs and the facilities critical to the derivation of those IROLs from the RC as per FAC-014-3 Requirement R6 above. While Parts 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired

		prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 in response to the retirement of FAC-010-3 to eliminate references to the PC determining IROLs. A future team should determine the appropriateness for the elements identified as applicable to 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
FAC-013-2	**Requirements** **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs).	R 1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The retirement of FAC-010-3 does not create a reliability gap here as SOLs will continue to be established by TOPs and communicated to PCs through FAC-014-3 Requirement R5. The PC can then use the SOL information to satisfy Requirement R1, R1.2. Requirement R1.2 does not specify whether the SOLs are sourced from the RC or by the PC. **Recommendations:** Consideration should also be given to clarify FAC-013-2 Requirement R1.2 to eliminate the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment.

		Possible solutions include changing the language of Requirement R1, R1.2 to reference the performance requirements per Table 1 of TPL-001-4, or revising the language to replace SOL with "Facility Ratings, System steady-state voltage limits, and the Transmission Planners' stability criteria." A future team should consider eliminating the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment as described above.
FAC-014-2	Requirements R3 – R5	Under Revision
INT standards		No Action Required
IRO standards		No Action Required
MOD standards		No Action Required
NUC standards		No Action Required
PER standards		No Action Required
PRC standards		
PRC-002-2	**Requirements:** **R5.** Each Responsible Entity shall: **5.1.** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.2.** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).	Direct language around SOL and IROL does not specify PC SOL methodology and therefore does not preclude the RC's methodology from determining the applicable limits. However, the time horizon for the requirement is "long-term planning." Additionally, the SOLs referred to are stability based only. The retirement of FAC-010-3 does not create a reliability gap here. IROLs and stability-related SOLs are communicated to the GOs

	5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).	and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." The Applicability section of PRC-002-2 describes the Responsibly Entities: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator Regardless of the designation of the Responsible Entity in a given Interconnection, either is able to provide the GOs and TOs the information in Requirement R5, Parts 5.1.2 and 5.1.4. The information is ultimately sourced from the RC, but FAC-014-3, Requirement R5, Parts 5.1, 5.2, and subparts requires the RC to communicate the relevant information to the PC, who, in turn, can communicate the information to the applicable GO and TO as required by PRC-002-2, Requirement R5, Parts 5.1.2 and 5.1.4. FAC-014-3 R5. Each Reliability Coordinator shall provide:

		5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). While subparts 5.1.2 and 5.1.4 of PRC-002-2 would benefit from a revision in response to the retirement of FAC-010, the need for such a revision does not rise to the level of creating a reliability gap if FAC-010 is retired prior to the time these requirements can be changed. **Recommendations:** It is recommended that this standard be modified at some point in the future to update the designation of the Responsible Entities defined in the Standard. In the absence of this change, however, the currently defined Responsible Entities are capable of providing the necessary information through the mechanisms described above.
PRC-023-4	**Attachment B** - Criteria Section:	Direct reference to FAC-010 made in this attachment.

	If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.	Attachment B sets the applicability of facilities operated below 200 kV (similar to FAC-003). These items reference PRC-023-4, Requirement R6, to which Attachment B is applicable. The language in part B2 of Attachment B of PRC-023-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-010-3; however, IROLs are established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." Accordingly, the GO and the TO are able to use the IROL information provided by the Reliability Coordinator. While part B2 of Attachment B for PRC-023-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise Attachment B of PRC-023-4 in response to the retirement of FAC-010-3 to eliminate the references to FAC-10, PC's determining IROLs and IROLs in the Planning Horizon for identification of circuits as a monitored Facility of an Interconnection Reliability Operating Limit (IROL).

		A future team should consider the appropriateness for the circuits identified as applicable to Attachment B of PRC-023-4 to include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
PRC-026-1	R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	Direct reference is made to the PC's SOL Methodology. Footnote 1 on page 3 of 84 references FAC-014-2, R3. Similar to the reference identified in Requirement R5, Part 5.1.2 of PRC-002-2, Requirement R1 of PRC-026-1 references the identification of facilities that are sensitive to angular stability constraints. Stability-related SOLs are communicated to the Planning Coordinator through FAC-014-3, Requirement R5, Parts 5.1 and, 5.2: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL;

		5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). With this information, the PC can communicate the necessary SOL information to the applicable GO and TO as required by PRC-026-1, Requirement R1. While Criteria 1 and 2 of PRC-026-1 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these criteria given the above requirement for the RC. **Recommendations:** Revise PRC-026-1, Requirement R1 in response to the retirement of FAC-010-3 to eliminate the term, "Planning Coordinator's Methodology" which references FAC-10 and remove the reference to SOLs identified by the PC. A future team should consider that the PRC-026 R1 criteria reference Elements associated with angular stability as identified in the PC or TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
TOP standards		No Action Required
TPL standards		No Action Required
VAR standards		No Action Required

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Mapping Document for FAC-010-3

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 provides the Planning Coordinator (PC) with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirements R4 and R5 address the communication and use of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in Planning Assessments between PCs and Transmission Planners (TPs).

FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R6 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for 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 P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **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. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-015-1 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **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. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1.	Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2.	State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
			to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **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.	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL Methodology. In the proposed construct, PC and TP identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via FAC-015-1, Requirement R6. IROLs are established by the RC as required by FAC-014-3. TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).
R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2.	Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 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.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 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.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **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	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 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	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		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.	
R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 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 TPL-001-4, 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	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		achieve required System performance. Examples of such actions include: • 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.	
R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **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.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3.	Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-~~3~~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:** ~~——~~ See Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme".~~Project 2015-09.

B. Requirements and Measures

R1. ~~The~~Each Reliability Coordinator shall have a ~~documented~~ methodology for ~~use in developing~~establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. ~~This~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

~~R1.~~R2. Each Reliability Coordinator shall~~:~~ include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

M2. ~~Include a description of how to identify the subset of SOLs that qualify~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.3.~~ Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as ~~IROLs.~~

3.1. ~~The~~ specified in the Reliability Coordinator's SOL Methodology ~~shall include a requirement that SOLs provide BES~~ ;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (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;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.4.~~4.1. Specify stability performance ~~consistent with~~ criteria, including any margins applied. The criteria shall include the following:

4.1.1. ~~In the pre-contingency~~ steady-state~~, the BES shall demonstrate~~ voltage stability;

4.1.2. transient~~, dynamic and~~ voltage response;

4.1.3. angular stability; ~~all Facilities shall be within their Facility Ratings and within their thermal, voltage and~~ and

4.1.4. System damping.

4.2. Require that stability limits~~. In~~ are established to meet the ~~determination of SOLs,~~criteria specified in Part 4.1 for the ~~BES condition used shall reflect current or expected system~~Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

~~1.5.~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions ~~and shall reflect~~ including any changes to ~~system~~System topology such as Facility outages~~.~~ ;

~~**1.6.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

4.5. ~~Single line to~~ Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or ~~3-~~three phase Fault (whichever is more severe~~),~~) with ~~Normal Clearing, on any Faulted~~ normal clearing, or without a Fault:

- generator~~, line, ~~;
- transmission circuit;
- transformer~~, or ~~;
- shunt device~~.~~; or

~~**1.6.1.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

- ~~Single~~single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

~~**1.7.** In determining the system's response to a~~ Any additional types of single Contingency~~, the following shall be acceptable:~~

~~[1] The Contingencies identified in FAC-011-R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~**1.7.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**1.7.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**1.7.3.** System reconfiguration through manual or automatic control or protection actions.~~

~~**1.8.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

~~**R2.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:~~

~~**2.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~**2.2.** Selection of applicable Contingencies~~

5.2. ~~A process for determining which of the~~ events identified for use in determining stability limits~~ associated with the list~~, or for use in performing OPAs and RTAs.

5.3. Any types of multiple ~~contingencies (~~Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

~~**2.3.**~~**5.4.** The method for considering the Contingency events provided by the Planning ~~Authority~~Coordinator in accordance with FAC-~~014~~015-1, Requirement ~~6) are applicable for use in the operating horizon given the actual or expected system conditions.~~ R6 to identify the Contingencies for use in determining stability limits.

~~**2.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~**2.4.** Level of detail of system models used to determine SOLs.~~

~~**2.5.** Allowed uses of Remedial Action Schemes.~~

~~**2.6.** Anticipated transmission system configuration, generation dispatch and Load level~~

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~**2.7.**~~**6.2.** Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_V.

M6. ~~The~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~**R3.**~~**R8.** Each Reliability Coordinator shall ~~issue~~provide its SOL Methodology and any changes to ~~that methodology,~~the SOL Methodology prior to the effective date of the SOL Methodology, to ~~the effectiveness of the Methodology or of a change to the Methodology, to all of the following: :~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~**3.1.**~~**8.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that ~~indicated~~requests and indicates it has a reliability-related need ~~for the methodology.~~;

8.2. Each Planning ~~Authority~~Coordinator and Transmission Planner that ~~models~~is responsible for planning any portion of the Reliability ~~Coordinator's~~Coordinator Area;

~~**3.2.**~~**8.3.** Each Transmission Operator within its Reliability Coordinator Area.

~~**3.3.** Each Transmission Operator~~ Acceptable evidence that ~~operates in~~ the Reliability Coordinator ~~Area.~~

~~C. Measures~~

~~**M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~**M2.**~~**M8.** ~~The Reliability Coordinator shall have evidence it issued~~provided its SOL Methodology~~, and any changes to that methodology, including the date they were issued, in accordance~~ to the entities identified in Requirement R8 may include, but is

not limited to, dated electronic or hard copy documentation such as emails with Requirement 4. receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

D.C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring ResponsibilityEnforcement Authority:
Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

Data"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.

1.3.1.2. Evidence Retention:
The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site auditThe following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by theits Compliance Monitor or within 15

business daysEnforcement Authority to retain specific evidence for a longer period of a requesttime as part of an investigation upon complaint:.

1.4.1 SOL Methodology.

1.4.2 Superseded portionsThe Reliability Coordinator shall keep data or evidence of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

- **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4with Requirements R1 through R3.7 and E1R8 for the current year plus the previous 12 calendar months. .

2.2. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.2.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.2.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.2.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.3. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

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	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
~~R1~~**R2.**	~~Not applicable.~~ N/A	~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~N/A	The Reliability Coordinator ~~has a documented~~ included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use ~~in developing SOLs within~~of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area~~, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~ did not include in its SOL Methodology the method for ~~use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1~~Transmission Operators to determine the applicable owner-provided Facility Ratings to be used~~.~~ ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use~~ in ~~developing SOLs within its Reliability Coordinator Area.~~operations.

~~R2~~**R3.**	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~ .	~~Not applicable.~~The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~.	~~The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)~~The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.
~~R3~~ **R4.**	The Reliability ~~Coordinator's~~Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's SOL Methodology is missing a description of~~Coordinator failed to incorporate four or more of the ~~following: R3.1 through R3.7~~Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of

				Requirement R5 into its SOL Methodology.
~~R3.6~~**R6.**	N/A	N/A	~~N/A~~The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_V) in its SOL Methodology.	~~N/A~~The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the

			Transmission Operator established.	periodicity of SOL communication.
~~R4~~**R8.**	The Reliability Coordinator ~~failed to issue~~provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to one of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change,~~accordance with Part 8.4 but was ~~provided to all the required entities no more~~late by less than or equal to 10 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator ~~failed to issue~~ provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to two of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology~~ accordance with Part 8.4, but was ~~provided to one or more of the required entities~~late by more than 10 calendar days ~~after the effectiveness of the change, but~~ but less than or equal to 20 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or~~to one ~~or more changes to that methodology to three~~ of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was~~ The Reliability Coordinator provided ~~to one or more of required entities~~its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days ~~after the effectiveness of the change, but~~ but less than or equal ~~to30~~to 30 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or one or more changes~~ to ~~that methodology to four~~two or more of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was provided~~ The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the ~~required entities more than30~~parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a

				requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days~~ after the effectiveness of the change~~. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

~~E.~~D. Regional ~~Differences~~Variances

~~3.~~ The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

~~3.1.~~ As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

~~3.1.1~~ Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

~~3.1.2~~ A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

~~3.1.3~~ Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

~~3.1.4~~ The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

~~3.1.5~~ A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

~~3.1.6~~ A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

~~3.1.7~~ The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

~~3.2.~~ SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

~~3.2.1~~ All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

~~3.2.2~~ Cascading does not occur.

~~3.2.3~~ Uncontrolled separation of the system does not occur.

~~**3.2.4** The system demonstrates transient, dynamic and voltage stability.~~

~~**3.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~**3.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~**3.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~**3.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~**3.3.1** Cascading does not occur.~~

~~**3.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
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~~4	~~November 19, 2015~~	~~FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.~~Project 2015-09 – Adopt revisions to standard.	Revisions

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "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." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.)" Real-time Assessment is defined in the NERC Glossary of Terms 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*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R6 and Part 6.1. R6. Each Reliability Coordinator shall include in its SOL Methodology 6.1. A description of how to identify the subset of SOLs that qualify as IROLs.	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	These requirements are addressed in: 1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs. 2. The definition of OPA and RTA 3. FAC-011-4, Requirement R4 addresses the establishment of stability limits and the associated performance requirements. 4. FAC-011-4 Requirement R6 and its Parts relating to IROLs.	"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	5. The definition of IROL and the TOP and IRO standards that address operation within IROLs. TOP-002-4, Requirement R1: 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 exceed any of its System Operating Limits (SOLs). TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL	implementation of an Operating Plan to address that SOL exceedance. The items in approved FAC-011-3, Requirement R2 and its sub-requirements are addressed through the related TOP standards that reference SOL exceedance. 1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances. 2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA. 3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once every 30 minutes to identify SOL exceedances. 4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances. 5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	exceedance identified as part of its Real-time monitoring or Real-time Assessment. IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time	6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA. 7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances. 8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA. The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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	Assessment is performed at least once every 30 minutes. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms 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*	limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state. Regarding the stability portions of Requirement R2, R2.1 and R2.2: FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.)" Real-time Assessment is defined in the NERC Glossary of Terms 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.)"*	Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements. Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology. Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area. Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.	RC to establish IROLs in accordance with its SOL Methodology. IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions. IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology: 6.1. A description of how to identify the subset of SOLs that qualify as IROLs. 6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V. FAC-014-3, Requirement R1: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). IRO-009-2, Requirement R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any 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 block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping.	Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
transmission system, and the transmission system topology.	4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other	standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	automatic post-Contingency mitigation actions. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. 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) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide	manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-012-3, 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. 5. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	than a NERC Reliability Standard requirement.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	• shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement R6 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits. FAC-015-1 Requirement R6: R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	In FAC-015-1, Requirement R6, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R6, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1]. Footnote 1 states "The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits."	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by including other automatic mitigation actions that are not a RAS, for example UVLS.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: 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 exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms 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.)"*	items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability	FAC-011-4, Requirement R6, Part 6.2 R6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R6, Part 6.2.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operating Limit (IROL) and criteria for developing any associated IROL T_V.	criteria for developing any associated IROL T_V.	
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R8, Parts 8.1 and 8.4: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology; 8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R8, Parts 8.1 and 8.4 Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it. Non-adjacent RCs, which are addressed in Part 8.4, do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Part 8.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.2 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.3 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R8, Part 8.3.

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Rationale for FAC-011-4

September 2017

Requirement R1

Each Reliability Coordinator shall have a methodology for establishing SOL (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires that the SOL Methodology shall be applicable for developing SOLs used in the operations horizon. The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires that the SOL Methodology state that SOLs shall not exceed associated Facility Ratings. Facility Ratings to be used in operations as System Operating Limits (SOLs) are addressed through FAC-011-4 Requirement R2 and therefore is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires that the SOL Methodology include a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs). This language is preserved in Requirement R6.

Requirement R2

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure that the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five

levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still responsible for determining the Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between the TOP and RC during operations.

Requirement R3

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1** Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;
- **3.2** Require that System Voltage Limits respect the Facility voltage Ratings;
- **3.3** Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;
- **3.4** Identify the lowest allowable System Voltage Limit;
- **3.5** Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;
- **3.6** Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;
- **3.7** Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its Reliability Coordinator Area for facility-based voltage limits, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identifies the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any Facility voltage Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any Facility voltage Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that UVLS should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are set above all UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1 Specify stability performance criteria, including any margins applied. The criteria shall include the following:

- **4.1.1** steady-state voltage stability;
- **4.1.2** transient voltage response;
- **4.1.3** angular stability;
- **4.1.4** System damping;

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5;

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area;

4.4 Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1].

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of system damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, this requirement may be met by providing language in the SOL Methodology describing which TOP (or identifying that the RC) has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out

[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10%, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the Reliability Coordinator Area (including other Reliability Coordinator Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require entire Reliability Coordinator Area modeling to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.6, UFLS programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS as a "last resort system preservation measure".

Requirement R5

Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1 The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device;
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2 Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4 The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in checking for all types of SOL exceedances in OPAs and RTAs (thermal, voltage and stability limits). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that at a minimum must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events such as inadvertent breaker operation and bus faults may be considered if the probability of such an event is relevant. The method for determining those Contingencies must also be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.4 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R6 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

Each Reliability Coordinator shall include in its SOL Methodology:

6.1 A description of how to identify the subset of SOLs that qualify as IROLs.
6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

Rationale R6

The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.

Requirement R7

Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Rationale R7

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R7 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own Transmission Operator Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R8

Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

8.1 Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;
8.2 Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;
8.3 Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4 Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

Rationale R8

Requirement R8 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses “responsible for planning” instead of “models any portion of” to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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 FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Part 8.4.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-2~~2~~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

~~**1.1.** Planning Authority~~

~~**1.2.** Transmission Planner~~

4.1.2. Transmission Operator

~~**2. Effective Date:** April 29, 2009~~

5. Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

~~The~~

R1. Each Reliability Coordinator shall ~~ensure that SOLs, including~~ establish Interconnection Reliability Operating Limits (IROLs~~),~~) for its Reliability Coordinator Area ~~are~~in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established ~~and that the SOLs (including Interconnection Reliability Operating Limits) are consistent~~IROLs in accordance with ~~its~~it SOL Methodology.

R2. ~~The~~Each Transmission Operator shall establish ~~SOLs (as directed by its Reliability Coordinator~~System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

~~**R1.**~~**R3.** The ~~Planning Authority~~Transmission Operator shall ~~establish SOLs, including IROLs, for~~provide its ~~Planning Authority Area that are consistent~~SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. ~~The Transmission Planner shall establish SOLs, including IROLs, for its~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission ~~Planning Area that are consistent~~Operator provided its SOLs in accordance with its ~~Planning Authority's~~Reliability Coordinator's SOL Methodology.

~~**R1.** The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:~~

R4. ~~The~~Each Reliability Coordinator shall ~~provide its SOLs~~establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) ~~to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and~~ at least once every twelve calendar months.

~~**1.1.**~~**5.2.** Each impacted Planning ~~Authorities~~Coordinator within its Reliability Coordinator Area~~. For~~, the following information for each established stability limit and each established IROL~~, the Reliability Coordinator shall provide the following supporting information~~ at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

~~**1.1.1.**~~**5.2.2.** Identification ~~and status~~ of the ~~associated Facility (or group of~~ Facilities~~)~~ that ~~is (~~are~~)~~ critical to the derivation of the stability limit or IROL~~.~~;

~~**1.1.2.**~~**5.2.3.** The ~~value of the IROL and its~~ associated IROL T_V~~.~~ for any IROL;

~~**1.1.3.**~~**5.2.4.** The associated Contingency(ies~~).~~); and

~~**1.1.4.**~~**5.2.5.** The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. ~~The~~Each impacted Transmission Operator ~~shall provide any SOLs it developed~~within its Reliability Coordinator Area, the value of the stability limits established pursuant to ~~its Reliability Coordinator~~Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame

necessary for inclusion in the Transmission ~~Service Providers that share its portion of the~~ Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

~~1.2.~~5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

~~**R1.1.** The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.~~

~~**R1.2.** The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

~~**R2.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

~~**R2.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~

~~**R2.2.** If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Each requesting Transmission Operator within its Reliability Coordinator~~.~~

~~A. Measures~~

5.5. ~~The~~ Area, requested SOL information for its Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each be able~~ Area, on a mutually agreed upon schedule.

~~**M4.**~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that ~~it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.** The~~ the Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.**~~**M5.** ~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and~~ provided the ~~list and the limits to its Reliability Coordinators~~information in accordance with Requirement ~~6~~R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

~~**2.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organization~~

~~**2.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~**2.3. Data Retention**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**2.4. Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**2.4.1** SOL Methodology(ies)~~

~~**2.4.2** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**2.4.3** Evidence that SOLs were distributed~~

~~**2.4.4** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**2.4.5** Distribution schedules provided by entities that requested SOLs~~

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

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.	~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs~~The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for ~~the~~its Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Reliability Coordinator's~~ its System Operating Limit Methodology ("SOL Methodology~~. (R1)~~") as established in FAC-011-4.
R2.	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	The Transmission Operator ~~has established~~did not establish SOLs for its portion of the Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the~~its Reliability Coordinator's SOL Methodology~~. (R2)~~
R3.	~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than,~~	~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50%~~	~~There are~~The Transmission Operator provided its SOLs	~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are~~

	~~25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~for the Planning~~to its Reliability Coordinator ~~Area~~, but ~~50% or more, but less than 75% of these~~did not provide its SOLs ~~are inconsistent with~~at the periodicity at which the ~~Planning Coordinator's SOL Methodology. (R3)~~RC needs such information to perform its reliability functions.	~~inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
R4.	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission ~~Planner has established SOLs for~~Operator in its ~~portion of the Planning~~Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Planning Coordinator's~~its SOL Methodology. ~~(R4)~~
R5 ~~.~~	~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting~~	~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45~~

	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~ The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~ The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~ The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6 ~~:~~	~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~N/A	~~Not applicable.~~N/A	~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ N/A	~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~The Reliability Coordinator with an established IROL, or the

				Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional ~~Differences~~Variances

None ~~identified.~~

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-014-2

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. 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. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		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 that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	1. FAC-011-4, Requirement R8, Part 8.2 2. FAC-015-1, Requirements R 1 – R6 FAC-011-4, Requirement R8, Part 8.2: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement R8, Part 8.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes made to FAC-011-4 and FAC-014-3 represent an improvement for

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-015-1: R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its	planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings used in Planning Assessments, Requirement R2 addresses the System steady state voltage limits used in Planning Assessments, and Requirement R3 addresses the stability performance criteria used in Planning Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more	Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. By implementing Requirements R1 – R5 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-	state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs,

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the	which addresses RC-to-RC communication and coordinated operations issues.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-015-1, Requirements R1 – R6 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-015-1, Requirements R1 –R6:	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. Implementing the processes required in FAC-015-1, Requirements R1 – R3

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the	provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. FAC-015-1, Requirements R1 – R5 result in PC and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-	Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation;	TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs 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. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement R8: 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. 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.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any),	FAC-015-1, Requirement R6 R6. Each Planning Coordinator shall communicate any instability, Cascading or	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows:

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	• FAC-015-1, Requirement R6 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement R6 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement R6 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement R6 because all instances of instability identified by the PC are to be communicated

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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		to the RC in accordance with FAC-015-1, Requirement R6. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement R6 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

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Rationales for FAC-014-3

September 2017

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. 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.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 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 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 SDT has removed the unnecessary and potentially confusing language. The

proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC who has wide-area responsibility will identify such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to identify stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area).

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area,, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and,

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOP)s. This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause of when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements in pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed

in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for SOLs to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Both Requirement R5 Parts 5.4 and 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Rationale R6

Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:

> *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*

Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.

The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

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 FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**

This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission

Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

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	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	The Planning Coordinator used less limiting stability	The Planning Coordinator used less limiting stability	The Planning Coordinator failed to implement a

		performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in the Reliability Coordinator's SOL Methodology.
R4.	N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.
R5.	N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

R6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-015-1

September 2017

Requirement R1

Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the Reliability Coordinator's (RC's) System Operating Limit (SOL) Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a Planning Coordinator (PC) area be coordinated between the PC and applicable Transmission Planners (TPs). It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC to use Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. If less limiting Facility Ratings are used by the PC, a technical justification is required to be documented and provided to the RC. This does

not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R2

Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R2

The purpose of TPL-001 is 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." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.
The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "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." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, the PC is required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R3

Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RCs SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the Reliability Coordinator's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When the PC performs the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R4

Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Requirement R5

Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Rationale R4 and R5

Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate

These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.

Requirement R6

Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its

Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** 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 required to address the instability, Cascading or uncontrolled separation;
- **6.5** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R6

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and Transmission Operators (TOPs).

The information itemized in Requirement R6 is a key consideration for RC and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R6 will supplement the severe System conditions identified Requirements R4 Parts 4.4 & 4.5 of TPL-001-4.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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 FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.

VSL Justifications for FAC-015-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R5	
Proposed VRF	**Medium**

This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

VSL Justifications for FAC-015-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R6	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2016-02 CIP Modifications

Standard Drafting Team Outreach Slides

RELIABILITY | ACCOUNTABILITY

Agenda

- Project 2016-02 Scope
- Status Updates
  - CIP-002-6
  - CIP-003-8
  - CIP-012-1
- Virtualization

CIP MOD SDT Scope

Issue Area	Source	Status
LERC definition	Order 822	Completed
Transient devices for low impact	Order 822	Completed
Communication between BES Control Centers	Order 822	Completed and CIP-012-1 going to August NERC BOT
Cyber Asset and BES Cyber Asset Definitions	V5TAG	Development in progress w/virtualization – 2 unofficial comment periods completed
Network and Externally Accessible Devices	V5TAG	Development in progress w/virtualization – 2 unofficial comment periods completed
Transmission Owner (TO) Control Centers (TOCC)	V5TAG	Awaiting CIP-002-6 IROL changes 2nd Comment & Ballot Period closed 4/30/2018

CIP MOD SDT Scope Continued

Issue Area	Source	Status
Virtualization	V5TAG	Development in progress – 2 unofficial comment periods completed
CIP Exceptional Circumstances (CIP SDT)	SAR	Drafting Completed – To be posted concurrent with Virtualization work
"Shared BES Cyber Systems" in CIP-002-5.1a	EnergySec RFI	Completed
IROL language	IROL Language SAR	CIP-002-6 going to August Standards Committee for authorization to post.
Malicious code	FERC Order No. 843	CIP-003-8 going to August Standards Committee for authorization to post.

Status Updates

- CIP-002-6 (IROL Language SAR)
  - Seeking Authorization to post at the August 22 Standards Committee (SC) meeting.
  - If approved, will be posted August 23 for a 45-day initial comment and ballot period.
- CIP-003-8 (FERC Order 843) Malicious Code Example
  - Seeking Authorization to post at the August 22 Standards Committee (SC) meeting.
  - If approved, will be posted August 23 for a 45-day initial comment and ballot period.
- CIP-012-1
  - Passed Final Ballot on August 13, 2018
  - NERC Board Adopted at August 15, 2018 Board Meeting

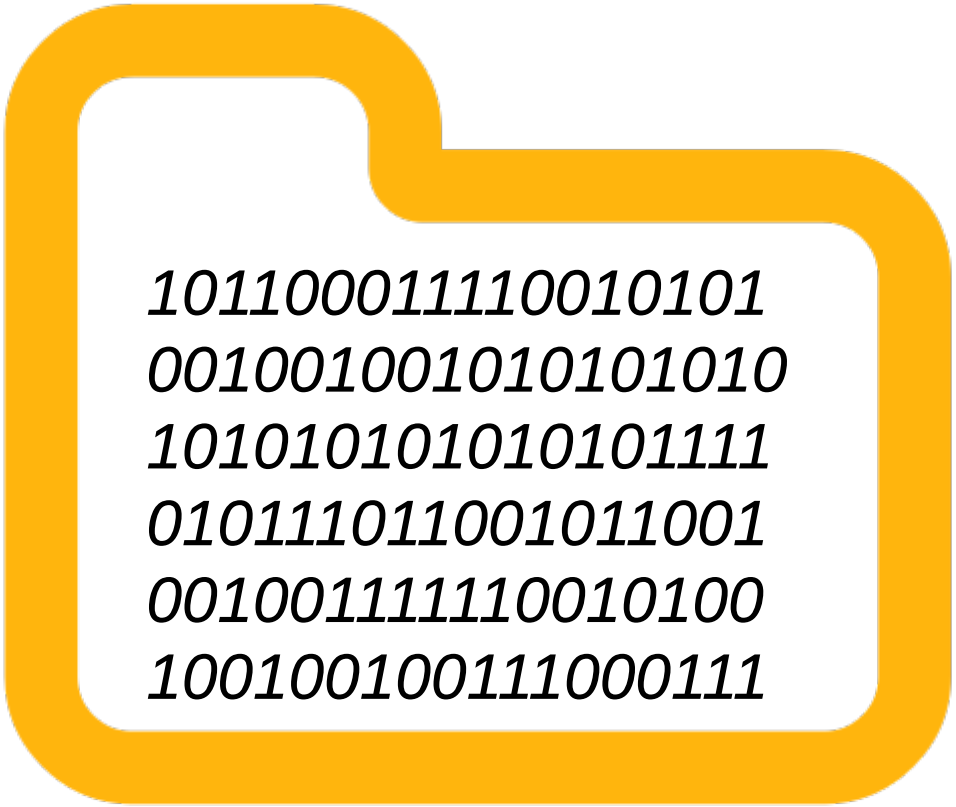
Virtualization

V5TAG Transfer - Virtualization

"The CIP Version 5 standards do not specifically address virtualization. However, because of the increasing use of virtualization in industrial control system environments, questions around treatment of virtualization within the CIP Standards are due for consideration.

The SDT should consider revisions to CIP-005 and the definitions of Cyber Asset and Electronic Access Point that make clear the permitted architecture and address the security risks of network, server and storage virtualization technologies."

(BES) Cyber Asset



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The SDT's Plate

Quick! Answer These!

- My control system database server is a VM. It exists as a logical construct, stored in a data file in a room of raw computing resources. Is it a BES Cyber Asset or is it just “software or data in those devices”?
- I have an image of a virtual server. Instances of that image are created and destroyed dynamically based on current workload. Are they BCAs? How do I say what the BCAs are in my BCS – I may have BCAs that exist for mere moments.
- What is the hypervisor in the CIP construct? Is it a BCA? An EACMS? Just “software in the device”?
- What can be shared on infrastructure with virtualized BES Cyber Systems? How should it be classified?

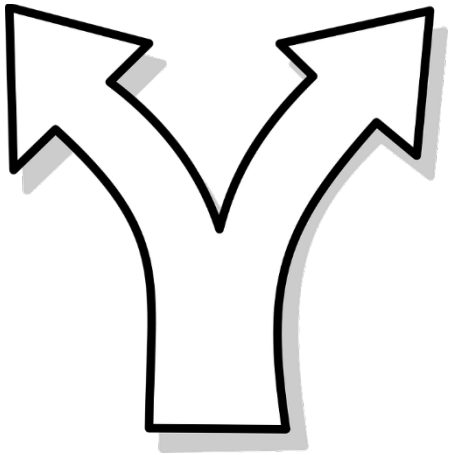
Quick! Answer These!

- Is a containerized application a BCA? Or is it just an application? If so, how do the CIP-007 requirements around OS work?
- My EAP is now a *policy* based "firewall" dynamically placed in front of workloads. Access control is now beyond a layer 3 routable protocol level. How do I show compliance with CIP-005?
- Is my SAN part of the same BES Cyber Asset as the virtual machine, is my SAN its own BES Cyber Asset, or is it just a BES Cyber System Information repository since it alone does not perform any BES functions?
- How do I handle sanitization for re-use when storage in my SAN is dynamically allocated amongst multiple cyber systems?

A Fork in the Road

The Left Path

- *Modify existing or create new definitions concerning devices and networking to include virtualization concepts*
- *Create additional technical requirements for securing today's version of virtualization technology.*

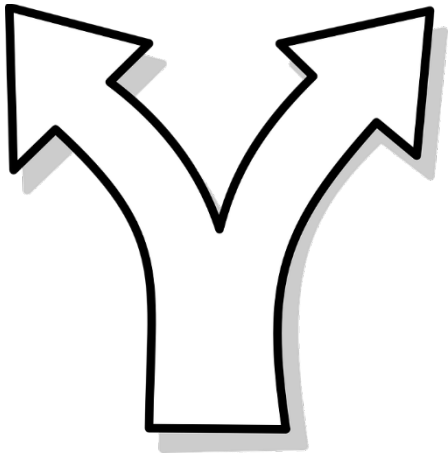


The Left Path

- SDT has worked for over a year on designing virtualization specific language and requirements
  - Electronic Security Zone – to logically isolate systems on shared infrastructure
  - Centralized Management System – to address the risk of virtualization management systems; “fewer, bigger buttons”
- Issues
  - Very complex
  - Today’s technology and products
  - Continues to evolve

The Right Path

- *Modify existing or create new definitions concerning devices and networking to include virtualization concepts*
- *Create additional technical requirements for securing today's version of virtualization technology.*



- *More fully embrace the Cyber System concept introduced in Version 5.*
- *Change existing prescriptive technical requirements to be more security objective based and future-proof.*

Backward Compatibility

Another Guiding Principle

Two "Sides" of CIP

- CIP is a PROGRAM and the programmatic elements are unchanged.
  - CIP-002, CIP-003, CIP-004, CIP-006, CIP-008, CIP-009, CIP-011
- CIP has TECHNICAL architecture requirements
  - CIP-005, CIP-007, CIP-010

Systems Versus Device Approach

- Make “BES Cyber System” the foundational object
- Requirements apply at the system level.
  - Implement on system as a whole
  - Implement on components that make sense
  - Allows for dynamic components

Current Example - Anti-Malware

- CIP-007-6 R3 Part 3.1

  "Deploy method(s) to deter, detect, or prevent malicious code."

- CIP-007-6 R3 Guidance

  "Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes."

Current CIP-005 R1 Parts

1.1 All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP.

1.2 All External Routable Connectivity must be through an identified Electronic Access Point (EAP).

1.3 Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.

CONCEPTUAL CIP-005 R1

CIP-005 R1

Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-6 Table R1* – to achieve the objective of mitigating the risk posed by unauthorized communications to and from applicable systems.

CONCEPTUAL CIP-005 R1

CIP-005 R1 Part 1.1

Have one or more methods to logically isolate applicable systems either individually or as a group, only allowing:

- Communication that has documented inbound and outbound access permissions including the reason for granting access; or
- Serial port connectivity such as RS-232 and RS-485.

Measures

Configuration of systems that enforce logical isolation such as Compute configuration (e.g. Hypervisor, containers), Storage System configuration (e.g. SAN, NAS, DAS), Network Infrastructure configuration (ACL,VLAN, VXLAN, MPLS)

Take Away

- Moving towards a fuller Cyber Systems approach
- Modify requirements to be more objective based and technology neutral
- Backwards Compatibility

SDT Meeting Schedule

2018 Planned Dates:

- September 18-20, 2018 (EDP Renewables – Houston, TX)
- October 23-25, 2018 (NERC – Atlanta, GA)
- November 13-15, 2018 (Tacoma Power, Tacoma, Washington)

Resources

- Information relative to the CIP Modifications project and SDT may be found on the Project 2016-02 Project Page under Related Files:

  Project 2016-02 Modifications to CIP Standards

- Jordan Mallory, NERC Standards Developer

  Jordan.Mallory@nerc.net

  404.446.2589 (Office)

Questions and Answers

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls		
Date Submitted:	April 24, 2018		
SAR Requester			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404.446.2589	Email:	Jordan.mallory@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
On April 19, 2018, the Federal Regulatory Energy Commission (Commission) issued Order No. 843 approving CIP-003-7 and directing NERC to develop modifications to Reliability Standard CIP-003-7 to mitigate the risk of malicious code that could result from third-party transient electronic devices.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
The purpose of this project is to address the Commission directive regarding third-party transient electronic devices contained in Order No. 843. These revisions will improve the security posture of responsible entities by clarifying compliance expectations.			
Project Scope (Define the parameters of the proposed project):			
The proposed project will address the Commission directive regarding third-party transient electronic devices in Order No. 843 through modifications to CIP-003-7 Reliability Standard. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standard.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The SDT shall address the Order No. 843 directive by developing modifications to Reliability Standard CIP-003-7. The Commission directed the following: *Per paragraph 37, "[The Commission] …direct[s] that NERC develop modifications to Reliability Standard CIP-003-7 to address our concern and ensure that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices. NERC could satisfactorily address the identified concern, for example, by modifying Section 5 of Attachment 1 to CIP-003-7 to clarify that responsible entities must implement controls to mitigate the risk of malicious code that could result from the use of third-party transient electronic devices."*
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional cost outside of the time and resources needed to serve on the Standard Drafting Team are expected. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, certain Distribution Providers, Generator Owner, Generator Operator, Interchange Coordinator or Interchange Authority, Reliability Coordinator, Transmission Owner, Transmission Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No consensus building has been completed to date.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
Project 2016-02 is currently working on addressing CIP directives and the V5TAG Transition document.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

NA

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

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

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SAR Status Tracking (Check off as appropriate)	
☒ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Critical Infrastructure Protection (CIP) Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization		
Date Submitted:	April 24, 2018		
SAR Requester			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404.446.2589	Email:	Jordan.mallory@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☒ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of this SAR is to transfer an issue currently within the scope of Project 2015-09 (Establish and Communicate System Operating Limits) to Project 2016-02 (Modifications to CIP Standards). Transferring the issue to Project 2016-02 will simplify the standards development process for stakeholders such that only one standard drafting team (SDT) is modifying Reliability Standard CIP-002, as explained below. As set out in its associated SAR, the purpose of Project 2015-09 is to revise the requirements in the Facilities Design, Connections, and Maintenance (FAC) group of standards for determining and communicating System Operating Limits (SOLs) to eliminate overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).			

Requested information
As relevant to this SAR, the SDT for Project 2015-09 is proposing to retire FAC-010-3 to eliminate overlap between the FAC standards and Reliability Standard TPL-001-4. With the retirement of FAC-010-3, Planning Coordinators and Transmission Planners would no longer be required to have a System Operating Limit (SOL) methodology to identify SOLs and IROLs. Reliability Standard CIP-002-5.1a (Impact Rating Criterion 2.6 in Attachment 1), however, references IROLs identified by Planning Coordinators and Transmission Planners. The Project 2015-09 SDT concluded that there is a need to modify CIP-002-5.1a to account for the retirement of FAC-010-3 and the elimination of a requirement for planners to identify SOLs and IROLs. The Project 2015-09 SDT developed draft language to replace the reference to such IROLs in Criterion 2.6 with other language that would allow Planning Coordinators and Transmission Planners to identify Facilities that otherwise do not meet the criteria in Section 2 of Attachment 1 but pose a higher risk to reliability such that its BES Cyber Systems should be protected as Medium Impact. In addition, the Project 2015-09 SDT recommends revising the IROLs reference in Impact Rating Criterion 2.9 in Attachment 1 to CIP-002-5.1a. Because the Project 2016-02 SDT is already modifying CIP-002-5.1a, this SAR would provide the Project 2016-02 SDT the authority to include the revisions provided by the Project 2015-09 SDT into the draft of CIP-002 to consolidate the comment period and ballot. The consolidated approach will avoid any confusion of having each SDT post the same standard for separate comment periods and ballots with different sets of changes.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
For the reasons discussed above, with the proposed retirement of FAC-010-3, the Project 2015-09 SDT identified a need to modify CIP-002-5.1a.
Project Scope (Define the parameters of the proposed project):
The Project 2016-02 SDT, which is currently making modifications to CIP-002-5.1a, will include modifications to the IROL language located in the Impact Rating Criteria of the CIP-002-5.1a provided by the Project 2015-09 SDT.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The Project 2015-09 SDT is proposing to revise the SOL/IROL-related FAC standards to reflect the notion that SOLs and IROLs should be developed and used in the operations horizon and not the planning horizon. To that end, the Project 2015-09 SDT proposes to retire the FAC-010-3 Reliability Standard, eliminating the requirement for Planning Coordinators to have a methodology for establishing SOLs for

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
use in the planning horizon, as well as the corresponding requirements in the FAC-014-2 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. The Project 2015-09 SDT reviewed the Reliability Standards that this proposed change would impact and determined to propose corresponding changes to those standards. Among others, the Project 2015-09 SDT identified CIP-002-5.1a, Attachment 1, Criteria 2.6 and 2.9 as requiring modifications. The Project 2015-09 SDT proposes the following changes: **2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its ~~Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner as ~~critical to the derivation of Interconnection Reliability Operating Limits (IROLs)~~an element of each Contingency event included in the Planning Assessment that result in System instability, Cascading, or uncontrolled separation ~~and their associated contingencies~~. **2.9.** Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in System instability, Cascading or uncontrolled separation~~cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable~~. More information on the rationale for the revisions proposed by the FAC SDT is located on the Project 2015-09 project page.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional cost outside of the time and resources needed to serve on the SDT are expected. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, certain Distribution Providers, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner

Requested information
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No consensus building has been completed to date, although the subject of this SAR has been developed by the Project 2015-09 SDT under its SAR.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
The Project 2016-02 SDT is currently working on addressing Federal Energy Regulatory Commission directives and the issues identified in the Version 5 Transition Advisory Group document as set forth in its associated SAR.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

NA

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.
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☐	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.

Market Interface Principles	
Does the proposed standard development project 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

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NA	

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SAR Status Tracking (Check off as appropriate)	
☒ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the ~~third~~ fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	February 10- March 13, 2017
45-day formal comment period with initial ballot	July 27 – September 11, 2017
45-day formal comment period with additional ballot	October 27 – December 11, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	May 18 – July 2, 2018

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~May 18 – July 2, 2018~~
10-day final ballot	July 30 – August 8, 2018
NERC Board	August 16, 2018

A. Introduction

1. **Title:** Cyber Security – Communications between Control Centers

2. **Number:** CIP-012-1

3. **Purpose:** To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.

4. **Applicability:**

   4.1. Functional Entities: The requirements in this standard apply to the following functional entities, referred to as "Responsible Entities," that own or operate a Control Center.

   4.1.1. Balancing Authority

   4.1.2. Generator Operator

   4.1.3. Generator Owner

   4.1.4. Reliability Coordinator

   4.1.5. Transmission Operator

   4.1.6. Transmission Owner

   4.2. Exemptions: The following are exempt from Reliability Standard CIP-012-1:

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

   4.2.2. 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. A Control Center at a generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation at which the transmitting Control Center is located.

5. **Effective Date:** See Implementation Plan for CIP-012-1.

B. Requirements and Measures

R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. The~~is~~ Responsible Entity is not required to include ~~requirement excludes~~ oral communications in its plan. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers;

1.2. Identification of where the Responsible Entity applied security protection ~~-~~for transmitting Real-time Assessment and Real-time monitoring data between Control Centers; and

1.3. If the Control Centers are owned or operated by different Responsible Entities, identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1 and documentation demonstrating the implementation of the plan(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC, 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~~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 ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Responsible Entities shall keep data or evidence of each Requirement in this Reliability 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 ~~Compliance Enforcement Authority~~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	The Responsible Entity documented its plan(s) but failed to include one of the applicable Pparts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable Pparts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1; Or The Responsible Entity failed to implement any Part of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Technical Rationale for CIP-012-1.

Implementation Guidance.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 822	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Cyber Security – Communications Between Control Centers

Implementation Guidance for CIP-012-1

RELIABILITY | ACCOUNTABILITY

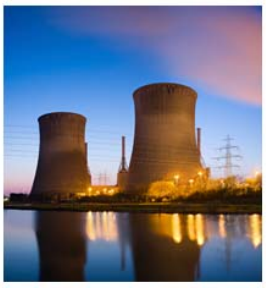

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Table of Contents

Introduction 3
Requirements 4
General Considerations 5
Identification of Security Protection 5
Identification of Where Security Protection is Applied by the Responsible Entity 5
Reference Model 7
Reference Model Discussion 7
Identification of Security Protection 8
Identification of Where Security Protection is Applied by the Responsible Entity 9
Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities 9
References 12

Introduction

The Project 2016-02 SDT drafted this Implementation Guidance to provide example approaches for compliance with CIP-012-1. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches that better fit their individual situations[1].

Responsible Entities may find it useful to consider this Implementation Guidance document along with the additional context and background provided in the SDT-developed Technical Rationale and Justification for CIP-012-1 document.

Background

The Commission issued Order No. 822 on January 21, 2016. Order 822 ~~approving seven~~approving seven CIP Reliability Standards and new or modified definitions, and directed modifications be made to the CIP Reliability Standards. Among other items, the Commission directed NERC to "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)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, the standard applies to all impact levels (i.e., high, medium, or low impact).

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both, to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment.

[1] NERC's Compliance Guidance Policy

Requirements

R1. *The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. ~~This requirement excludes oral communications~~The Responsible Entity is not required to include oral communications in its plan. The plan shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers;

1.2. Identification of where the Responsible Entity applied security protection for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3. If the Control Centers are owned or operated by different Responsible Entities, identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.

General Considerations

Plan Development

As noted in the Technical Rationale and Justification for CIP-012-1, the focus of Requirement R1 is ~~-~~implementing a documented plan to protect information that is critical to the real-time operations of the Bulk Electric System while in transit between applicable Control Centers. The number of plan(s) and their content may vary depending on a Responsible Entity's management structure and operating conditions. The Responsible Entity may document as many plans as necessary to meet its needs. For instance, a Responsible Entity may choose to document one plan per Control Center or choose an all-inclusive, single plan for its Control Center communication environment. A Responsible Entity may choose to document one plan for communications between Control Centers it owns and a separate plan for communications between its Control Centers and the Control Centers of a neighboring Entity. The number and structure of the plans is at the discretion of the Responsible Entity as long as the plan(s) include the required elements described in parts 1.1, 1.2, and 1.3 of Requirement R1.

Identification of Security Protection

Entities have latitude to identify and choose which security protection is used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers.

This security protection could consist of logical protection, physical protection, or some combination of both. To determine security protection, the requirement specifies that it must mitigate the risk of unauthorized disclosure or modification of applicable data.

Security protection implementation can be demonstrated in many ways. If a Responsible Entity uses physical protection, it may demonstrate implementation through review of an applicable Control Center floor plan with details subsequently confirmed through visual inspection, which identifies the physical security measures in place protecting the communication link. If the Responsible Entity uses logical protection, it may demonstrate implementation through an export of the device configuration which applies the security protection. Alternatively, a Responsible Entity may demonstrate implementation through security control monitoring, using an automated monitoring tool to generate reports on the encryption service used to protect a communications link. Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.

Identification of ~~-~~Where Security Protection is Applied by the Responsible Entity

A Responsible Entity should consider its environment when identifying where security protections should be applied. One approach is to implement security within the Control Center itself to ensure that data confidentiality and integrity is protected throughout the transmission. The Responsible Entity can identify where security protection is applied using a logical or physical location The application of security in accordance with CIP-012 requirements does not add additional assets to the scope of the CIP Reliability Standards. Locations of applied security protection may vary based on many factors such as impact levels of the Control Center, different technologies, or infrastructures. Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.

Identification of where a Responsible Entity applies security protection could be demonstrated with a list or a Control Center diagram showing either physical or logical security controls. Physical diagrams may require visual

confirmation of these controls. These diagrams or a list could be included within the plan developed for R1. A Responsible Entity could also use labels to identify on-site devices where CIP-012 security protection is applied.

When exchanging data between two entities, if a Responsible Entity only manages one end of a communication link, the Responsible Entity is not responsible for identifying where the security protection is applied by the neighboring entity with ~~whom~~which it is exchanging data. ~~–~~However, if a Responsible Entity has taken responsibility for both ends of the communication link (such as by placing a router within the neighboring entity's data center), then the Responsible Entity shall identify where the security protection is applied at both ends of the link.

Similarly, if a Responsible Entity owns and operates both Control Centers which are exchanging data (such as in the case of a primary and backup Control Center), then the Responsible Entity shall identify where security protection is applied at both ends of the link.

Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

The Technical Rationale and Justification for CIP-012-1 identifies key considerations in the Control Center Ownership section when communications between Control Centers with different owners or operators. Many operational relationships between Responsible Entities are unique. Consequently, there is no single way to identify responsibilities for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between Control Centers.

Implementation of responsibilities could also be demonstrated in many ways. Some examples include a joint procedure, a memorandum of understanding, or meeting minutes between the two parties where responsibilities are defined.

Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP. ~~–~~These responsibilities should be included in both Responsible Entities' plans satisfying requirement part 1.3.

Reference Model

For this Implementation Guidance, the SDT uses a basic reference model of Primary and Backup Control Centers (Entity Alpha) to illustrate approaches to demonstrating compliance. These Control Centers communicate to each other and to a neighboring entity's Control Center (Entity Beta) in configurations outlined by the diagrams in this section. The SDT recognizes that the reference model does not contain many of the complexities of a real Control Center. For this Implementation Guidance, the registration or functions performed in the reference model Control Center are also not considered. A high level block diagram of the basic reference model is shown below in Figure 1. -This Implementation Guidance is developed from the perspective of Entity Alpha.

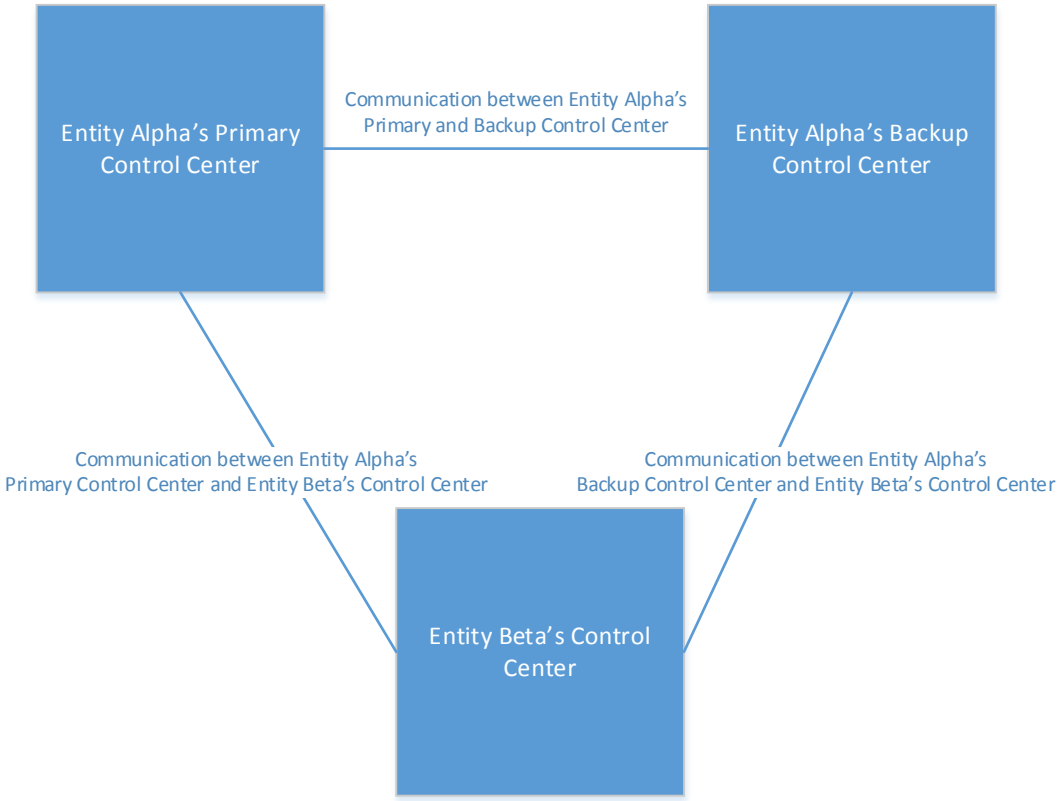

Figure 1: High Level Block Diagram of Reference Model Control Centers

Reference Model Discussion

Requirement R1 requires the implementation of a documented plan. To comply with requirement R1, one approach to a plan is to first determine which communications are in scope of CIP-012-1. There are multiple ways to identify an entity's scope in R1. For example, Entity Alpha in the reference model may first identify the Control Centers with which it communicates. Entity Alpha would determine that there are three: Entity Alpha's Primary Control Center, Entity Alpha's Backup Control Center, and Entity Beta's Control Center.– Entity Alpha does not need to consider whether Entity Beta further shares its data with another Entity. That is the responsibility of Entity Beta and is outside of Entity Alpha's purview. Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. –These communications are out of scope for CIP-012-1.

Now that Entity Alpha has identified the Control Centers with which it communicates, Entity Alpha identifies either: (1) the Real-time Assessment and Real-time monitoring data; or (2) communication links which are used to transmit Real-time Assessment and Real-time monitoring data between Control Centers. In either case, Entity Alpha should refer to the data specification for Real-time Assessment and Real-time monitoring data identified in

TOP-003-3 and IRO-010-2. For this reference model scenario, identifying the communication links used to transmit Real-time Assessment and Real-time monitoring data may be the most straightforward approach. Through an evaluation of communication links between Control Centers and an evaluation of how it transmits and receives Real-time Assessment and Real-time monitoring data, Entity Alpha determined that it communicates applicable data between its primary and backup Control Centers across a single communication link. Entity Alpha also determined that it communicates applicable data to and from Entity Beta's Control Center across one of two links that originate from either Entity Alpha's primary or backup Control Center using the Inter-Control Center Communications Protocol (ICCP).

With an identified scope of communications links, Entity Alpha now considers the three required elements of its required communications between Control Centers for its plan.

Identification of Security Protection

- Entity Alpha must ensure that protection is applied where identified in its CIP-012-1 plan. The protection must also meet the security objective of mitigating the risk of unauthorized disclosure or modification of applicable data while in transit between Control Centers. The identification of security protection could be demonstrated by a network diagram similar to that shown in Figure 2 or Figure 3.
- In a simple case where the security protection is applied sufficiently close to the Control Center, such as within the Physical Security Perimeter of the Control Center, Entity Alpha may use a single security protection method to meet the security objective. For this case, shown in Figure 2, Entity Alpha implements a Virtual Private Network (VPN) connection across a private leased communication circuit for each of its three in-scope communication links. To meet the security objective, Entity Alpha further states that its VPN uses Internet Protocol security (IPsec) with encryption.
- For more complex scenarios, Entity Alpha may need to use a combination of security controls. ~~–~~For instance, in Figure 3, Entity Alpha uses a combination of physical security controls (physical access control) and logical security controls (encrypted communications consistent with the first scenario above) to meet the security objective.~~–~~ The SDT notes that the same technical architecture could exist where the responsibilities of the registered entities are different. ~~Alternately~~Therefore as shown in Figure 2 & 3, in the scenario where entity Alpha owns and operationally manages the communication link and endpoint equipment, Entity Beta is responsible for ensuring the communication endpoint of the communication link is within a Control Center. Entity Beta ensures Entity Alpha's communication link endpoint equipment is within a Control Center by including the communication endpoint within a Control Center PSP. ~~–~~The physical controls for the PSP are described in CIP-006 documentation and do not need to be repeated for this requirement. This satisfies Entity Beta's obligation for Part 1.1 and 1.2.
- While these scenarios are all specific to communication links, it is possible that Entity Alpha and Entity Beta achieve the security objective by applying protection to the data rather than the communication links. In this scenario, the application enabling the data exchange between Control Centers may be capable of applying security controls directly to the data. These security controls mitigate the risk of unauthorized disclosure or modification of applicable data rather than relying on lower level network services to provide this security. For instance, Entity Alpha and Entity Beta may apply security protection at the application layer by using Secure ICCP to exchange applicable data. According to a report released by Sandia National Labs[2], Secure ICCP provides "data integrity indirectly by providing a cryptographic checksum. Secure ICCP provides data confidentiality by encrypting ICCP data exchanges." Methods other than Secure ICCP could also be used to apply security protection to the data at the application layer.
- It is theoretically possible that Entity Alpha and Entity Beta could exchange Real-time Assessment data between Control Centers by email. In that scenario, one approach may be for Entity Alpha to email the

[2] https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/19-Secure_ICCP_Integration.pdf

applicable data to Entity Beta's Control Center in a protected container such as an encrypted zip file. Entity Alpha and Entity Beta can then exchange the password to that encrypted container through another method, such as by phone. While the notional example of protecting data exchanged by email is a useful illustration of how to achieve the security objective of CIP-012-1, it is extremely unlikely to be used in practice. The characteristics of email communication are inconsistent with the requirements of Real-time data exchange.

Identification of Where Security Protection is Applied by the Responsible Entity

Similar to the identification of security protection above, the identification of where security protection is applied can also be demonstrated by a network diagram similar to those found in Figures 2 and 3.

- Figure 2 shows the identification where CIP-012-1 security protection is applied for the Entity Alpha reference model when a single encrypted tunnel is used to implement the required protection. Entity Alpha has identified that security protection is applied at each of its Control Centers on the external Ethernet interface on the WAN router. While the diagram depicts where Entity Beta has applied security protection for illustrative purposes, Entity Alpha is not responsible for identifying where Entity Beta has applied security protection.

- In order to understand the application of security protection in context of who controls the communication link, it may be helpful to identify both where CIP-012-1 security protection is applied and the location of the telecommunications carrier (telco) demarcation point. Figure 3 provides such an example where the telco demarcation point may not be within the Control Center and based the facts and ~~circumstances surrounding this scenario, Entity Alpha has~~circumstances~~'~~ surrounding this scenario, Entity Alpha has implemented a combination of security controls to comply with CIP-012-1. In this scenario, Entity Alpha identifies that it has applied physical security protection for its PSP and continuing for its WAN router and that it has applied logical security protection (encryption) at the WAN router. Entity Alpha has also identified the telco demarcation point at a point in the telecommunications cabling connecting to Entity Alpha's WAN router, perhaps at a punch down block for example. In Figure 3, the telco demarcation point is inside the same room as the WAN router. The telco demarcation points are referenced in the drawing for clarity, but are not part of the plan.

- Figure 2 & 3 provides an example of where the operational obligations of an entire communications link, including both endpoints, belong to Entity Alpha. -In this case, Entity Beta may be responsible for ensuring the communications endpoint of the communications link is within their Control Center. Entity Beta ensures Entity Alpha's communication link endpoint equipment is within a Control Center by including the communication endpoint within a Control Center PSP. The documentation provided for Part 1.1 by Entity Beta fulfils this obligation.

- The data-centric scenario described above is less intuitive for identifying where security protection is applied by Entity Alpha. If security protection is applied at the application layer (such as Secure ICCP), Entity Alpha could reasonably identify the application or service applying the security (such as the Secure ICCP service) as the location of where security protection is applied.

Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

Entity Alpha and Entity Beta may determine they each are responsible for one end of the VPN configuration on their respective WAN routers. Entity Alpha and Entity Beta have agreed to a 30 character pre-shared key for IPSec authentication.

Rather than use a pre-shared key, Entity Alpha and Entity Beta may decide to use digital certificates for the IPSec authentication using a trusted certificate authority. In that scenario, Entity Alpha and Entity Beta would agree on who is the party responsible for managing the certificate authority.

In the example where the communication link and endpoint equipment are owned by Entity Alpha, both entities should include ownership responsibilities in their plans satisfying requirement 1.3. Examples include but are not limited to, a letter ~~stating~~ indicating ownership or responsibility, a copy of a contract indicating ownership or responsibilities, an excerpt from an operational agreement or manual indicating ownership or responsibility.

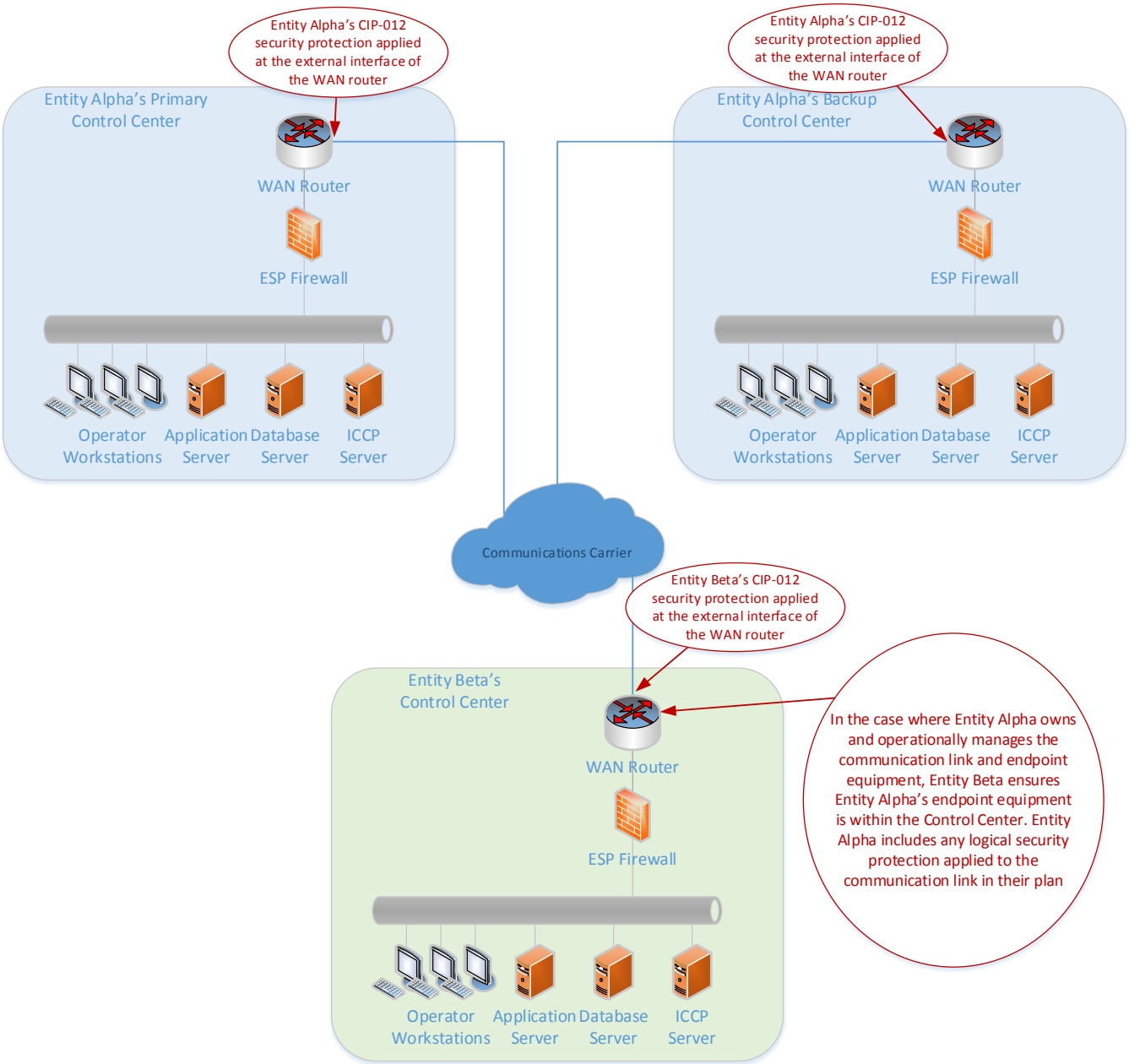

Figure 2: Network diagram and identification of where security protection is applied

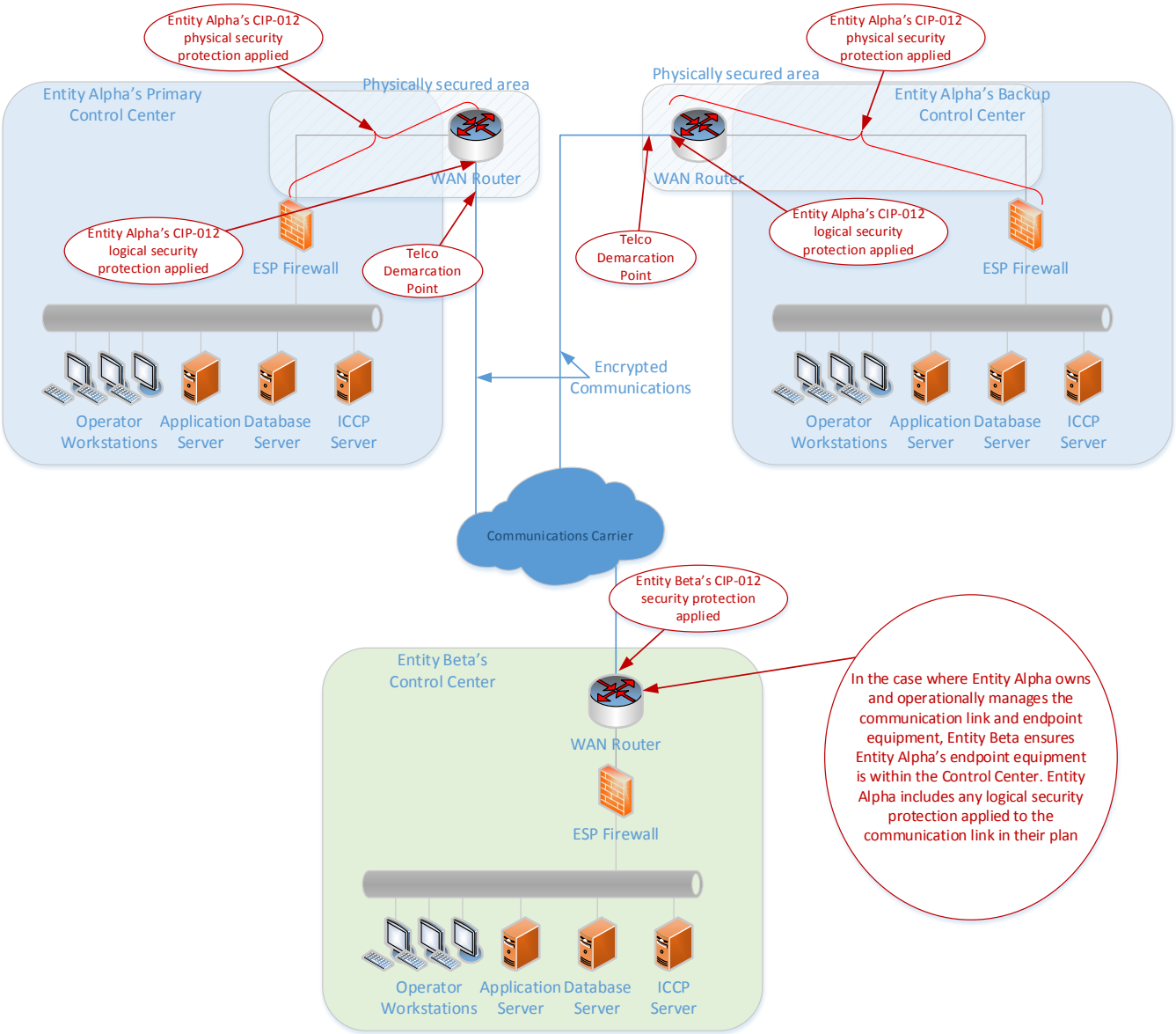

Figure 3: Network diagram using a combination of controls for CIP-012-1

References

Mitre Common Weakness Enumeration (CWE™) list of software weakness types
https://cwe.mitre.org/data/definitions/327.html

Cryptographic Standards and Guidelines
https://csrc.nist.gov/Projects/Cryptographic-Standards-and-Guidelines

NIST Special Publication 800-175B
Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
http://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-175B.pdf

Guide to Cryptography
https://www.owasp.org/index.php/Guide_to_Cryptography#Symmetric_Cryptography

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-012-1

Applicable Standard

- Reliability Standard CIP-012-1 - Cyber Security – Communications between Control Centers

Requested Retirements

- None

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-012-1 - Cyber Security – Communications between Control Centers

Where approval by an applicable governmental authority is required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) 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-012-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-012-1**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

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-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements to mitigate the risk of the unauthorized disclosure or modification of data used for Real-time Assessments and Real-time monitoring while being transmitted between Control Centers.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirement complements CIP-005-1, Requirement R1, CIP-006-6, Requirement R1, and CIP-007-6, Requirement R1 which are related to security of networks and communications components. The proposed VRF is consistent with these related requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to have a cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-012-1, Requirement R1	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Responsible Entity documented its plan(s) but failed to include one of the applicable ~~p~~Parts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable ~~p~~Parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1; Or The Responsible Entity failed to implement any Part of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

VSL Justifications for CIP-012-1 Requirements R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL does not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement is for the Responsible Entity to implement one or more documented plan(s) as specified in Requirement R1. The moderate VSL addresses where the Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1. The high VSL addresses where the Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1. The severe VSL addresses where the Responsible Entity failed to document plan(s) for Requirement R1, or where the Responsible Entity failed to implement plan(s) for Requirement R1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

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DRAFT

Cyber Security – Communications between Control Centers

Technical Rationale and Justification for Reliability Standard CIP-012-1

~~March~~ May 2018

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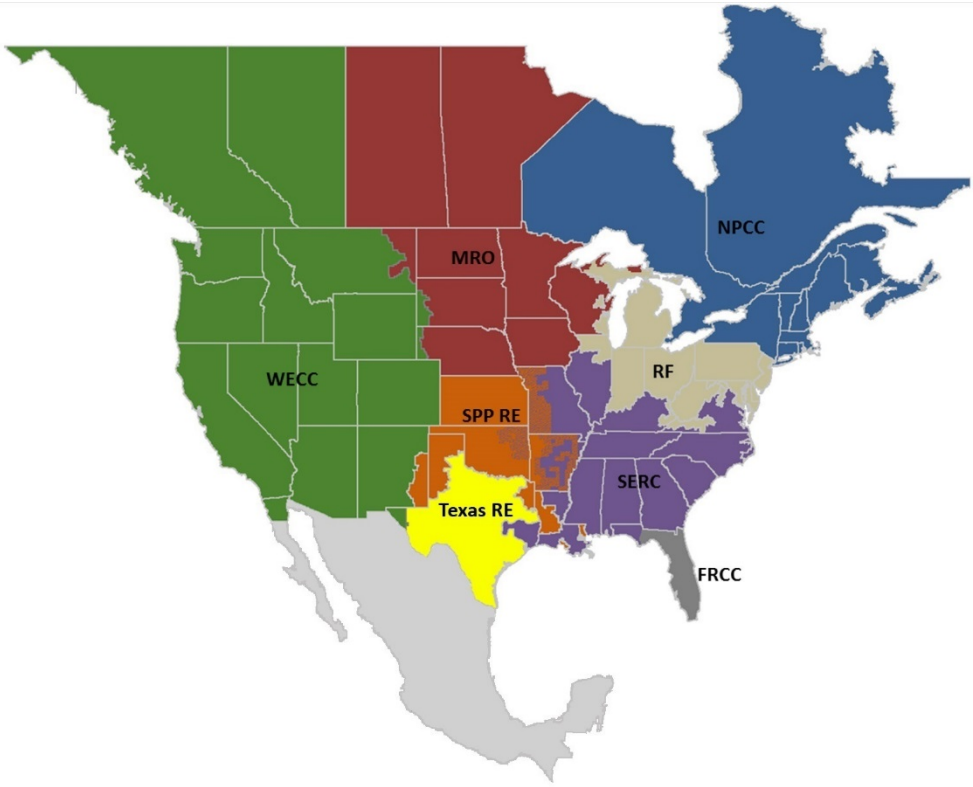
Table of Contents

Preface iii
Introduction iv
Requirement R1 1
General Considerations for Requirement R1 1
Overview of confidentiality and integrity 1
Alignment with IRO and TOP standards 1
Identification of Where Security Protection is Applied by the Responsible Entity 2
Control Center Ownership 2
References 4

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into eight 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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard CIP-012-1. It will provide stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. It also contains information on the SDT's intent in drafting the requirements. This Technical Rationale and Justification for CIP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

On January 21, 2016, the Federal Energy Regulatory Commission (FERC or Commission) issued Order No. 822, approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified terms in the Glossary of Terms Used in NERC Reliability Standards, and directing modifications to the CIP Reliability Standards. Among others, the Commission directed the North American Electric Reliability Corporation (NERC) to "develop modifications to the CIP Reliability Standards to require Responsible Entities[1] 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)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, as defined in the Glossary of Terms Used in NERC Reliability Standards, the standard applies to all impact levels (i.e., high, medium, or low impact).

Although the Commission directed NERC to develop modifications to CIP-006, the SDT determined that modifications to CIP-006 would not be appropriate. There are differences between the plan(s) required to be developed and implemented for CIP-012-1 and the protection required in CIP-006-6 Requirement R1 Part 1.10. CIP-012-1 Requirements R1 and R2 protect the applicable data during transmission between two separate Control Centers. CIP-006 Requirement R1 Part 1.10 protects nonprogrammable communication components within an Electronic Security Perimeter (ESP) but outside of a Physical Security Perimeter (PSP). The transmission of applicable data between Control Centers takes place outside of an ESP. Therefore, the protection contained in CIP-006-6 Requirement R1 Part 1.10 does not apply.

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment.

CIP-012 Exemption (4.2.3) for certain Control Centers

As the SDT drafted CIP-012, it became aware of certain generating plant or Transmission substation situations where such field assets could be dual-classified as Control Centers based on the current Control Center definition. However, their communications to their normal BA or TOP Control Center are not the type of communications that are the intended scope of CIP-012 as they do not differ from any other generating plant or substation. The SDT wrote an exemption (Section 4.2.3 within CIP-012) for this particular scenario which is described in further detail below.

[1] As used in the CIP Standards, a Responsible Entity refers to the registered entities subject to the CIP Standards.

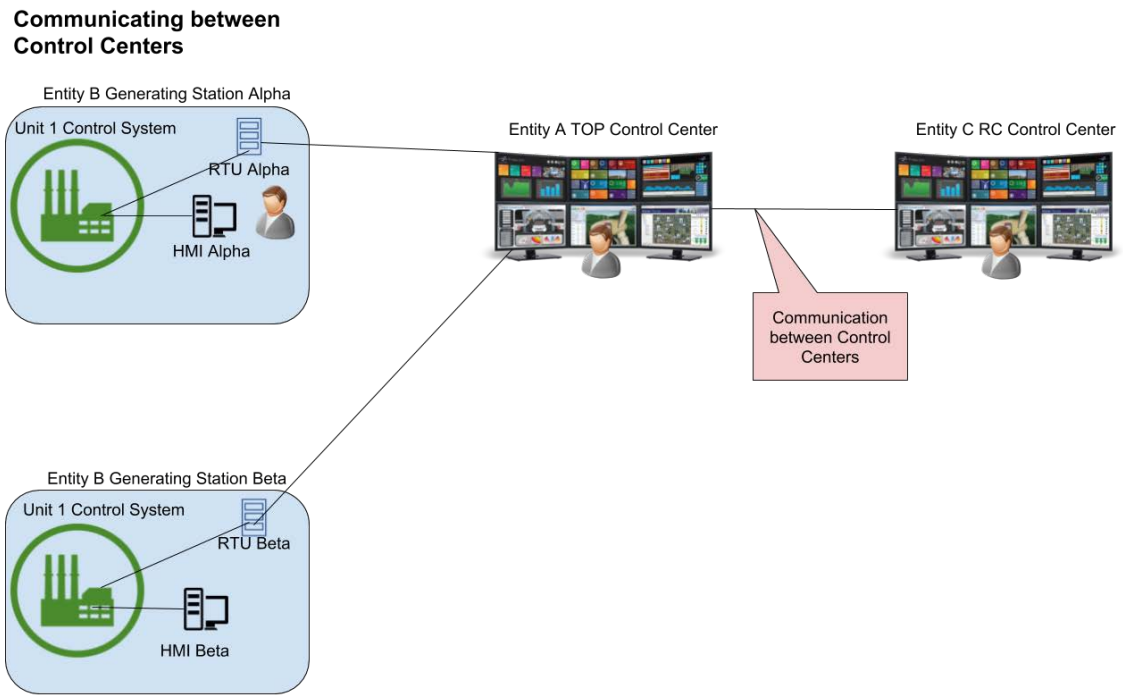


Figure 1

Figure 1 above pictures a typical scenario with two Control Centers communicating (in this instance Entity C's RC Control Center and Entity A's TOP Control Center). The communication between them is the intended scope of CIP-012's requirements if it meets the types of data inclusions and exclusions within the standard. The TOP Control Center is communicating with an RTU at two of Entity B's generating plants (Stations Alpha and Beta) and those RTU's are gathering information from each generating unit's control system. Each generating unit at each plant has an HMI (Human/Machine Interface; an operator workstation) that the local personnel use to operate their respective units.

Entity B decides that the generating unit at Station Beta, a small peaking facility, will only have an operator on site during the day and the operator at Station Alpha should be able to remotely start the unit at Station Beta if necessary.

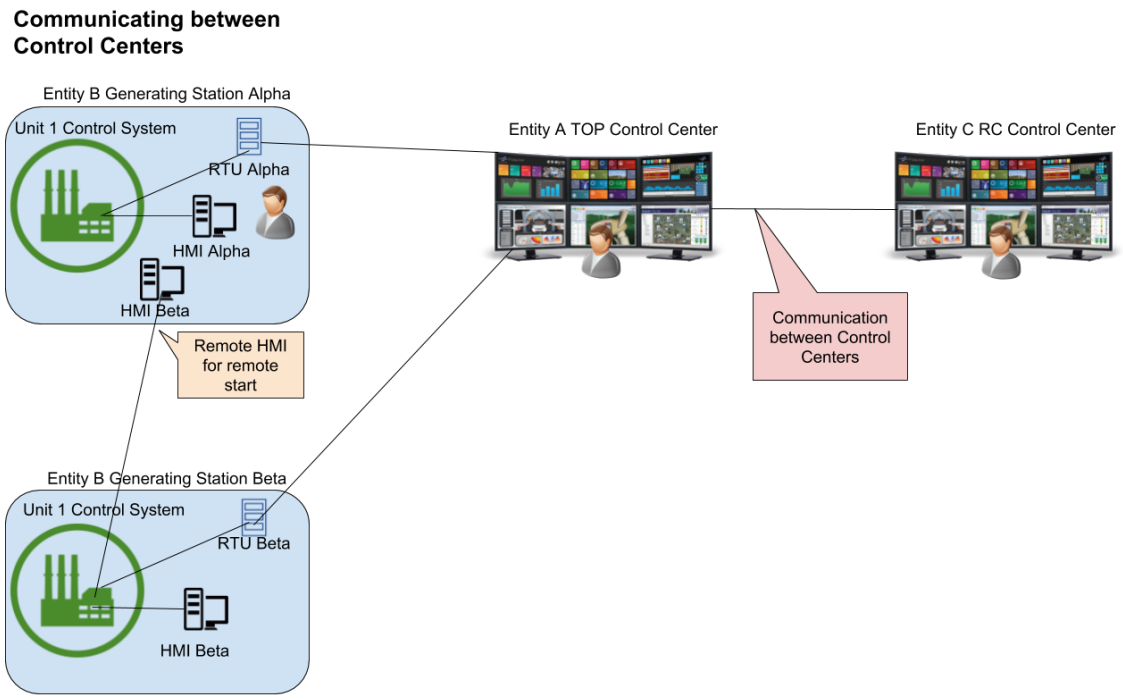


Figure 2

In Figure 2, Entity B installs a dedicated communications circuit from the control system on Station Beta's control system and puts a dedicated HMI at Station Alpha the operator can use. Station Alpha is now "one or more facilities hosting operating personnel that monitor and control the BES in real time to perform the reliability tasks of…a Generator Operator for generation Facilities at two or more locations." It can now be dual-classified not only as a generation resource but also as a Control Center.

The communications to the TOP and RC Control Centers from Figure 1 have not changed at all. –No new cyber systems are in place that can impact multiple units. -No cyber systems have been added performing Control Center functions. No additional risk from cyber systems has been added. -The only thing that has changed is an HMI for Station Beta has been moved within close physical proximity to an HMI for Station Alpha.

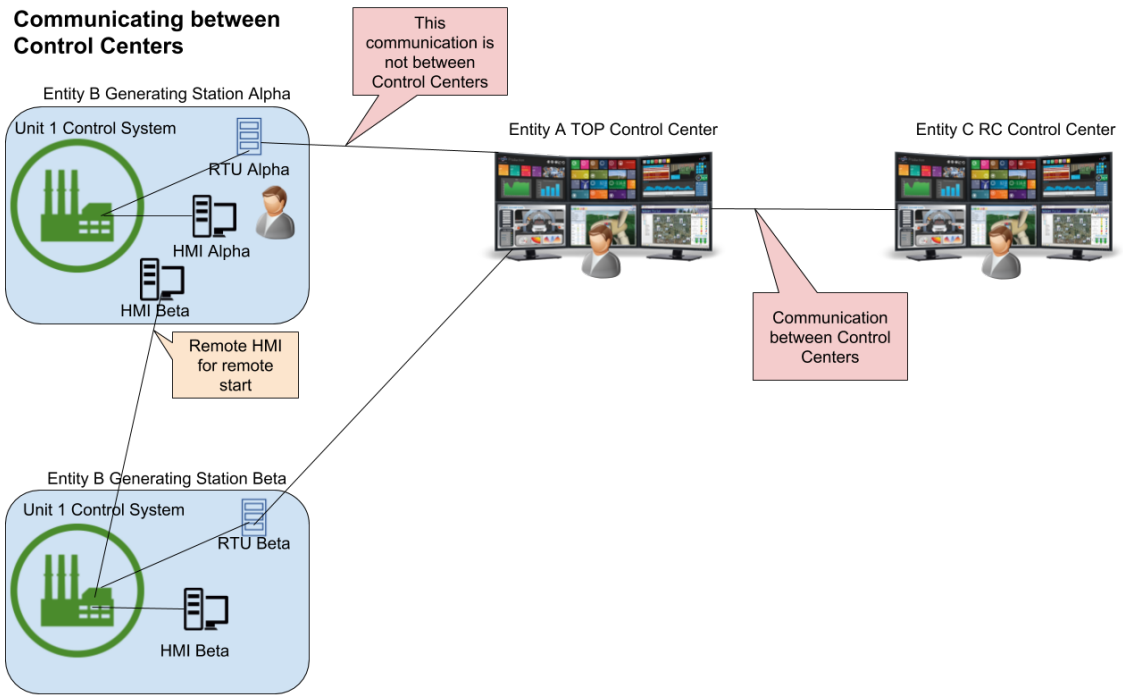


Figure 3

The SDT realized how this suddenly makes the communication noted in Figure 3 between Station Alpha and Entity A's TOP Control Center subject to CIP-012 although nothing has changed between them. —There is no new risk involved. -Two HMI's have been moved into the same room and suddenly a new NERC CIP standard applies to two entities.

This is an anamoly of the current Control Center definition defining a facility, room, or building from which something can be done without regard to how its done or with what systems. This is a generation specific example, but the SDT can envision substations with an HMI or protective relay that "operating personnel" within the substation could use to impact an adjacent substation. The SDT realizes that in the criteria for TO's and GOP's the "two or more geographic locations" is not a precise enough filter for capturing what a Control Center truly is. The SDT's attempts to address this issue by clarifying the definition of Control Center pointed out larger issues that are not within the SDT's SAR to address at this time. Therefore the SDT is handling the issue this creates for CIP-012 by the 4.2.3 exemption within the CIP-012 standard which reads:

> 4.2.3. ————A Control Center at a generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation at which the transmitting Control Center is located.
> ~~Control Centers located at a generation resource or Transmission station or substation that transmits Real-time Assessment and Real-time monitoring data to another Control Center and that data pertains only to the generation resource or Transmission station or substation at which the Control Center is located.~~

The intent of this exemption is to exclude the normal RTU-style communication from a field asset about that field asset's status from CIP-012. -Throughout this scenario or others like it, that communication has not changed and is still the same data pertaining only to the single location. -The SDT recognizes that this communication is not the

intent of the standard for protecting communications between Control Centers and this type of communications can be using older legacy communication technology and protocols.

Requirement R1

R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. ~~This requirement excludes oral communications.~~ The Responsible Entity is not required to include oral communications in its plan. ~~-~~The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 *Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring while being transmitted between Control Centers;*

1.2 *Identification of where the Responsible Entity applied security protection for transmitting Real-time Assessment and Real-time monitoring data between Control Centers; and*

1.3 *If he Control Centers are owned or operated by different Responsible Entities,identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.*

General Considerations for Requirement R1

Requirement R1 focuses on implementing a documented plan to protect information that is critical to the Real-time operations of the Bulk Electric System while in transit between applicable Control Centers. The SDT does not intend for the listed order of the three requirement parts to convey any sequence or significance.

Overview of confidentiality and integrity

The SDT drafted CIP-012-1 to address confidentiality and integrity of Real-time Assessment and Real-time monitoring data. This is accomplished by drafting the requirement to mitigate the risk of unauthorized disclosure (confidentiality) or modification (integrity). For this Standard, the SDT relied on the definitions of confidentiality and integrity as defined by National Institute of Standards and Technology (NIST):

- Confidentiality is defined as, "Preserving authorized restrictions on information access and disclosure, including means for protecting personal privacy and proprietary information."[2]
- Integrity is defined as, "Guarding against improper information modification or destruction, and includes ensuring information non-repudiation and authenticity."[3]

The SDT asserts that the availability of this data is already required by the performance obligation of the Operating and Planning Reliability Standards. The SDT drafted CIP-012 to address the data while being transmitted. The SDT maintains that this data resides within BES Cyber Systems, and while at rest is protected by CIP-003 through CIP-011.

Alignment with IRO and TOP standards

The SDT recognized the FERC reference to additional Reliability Standards and the responsibilities to protect the applicable data in accordance with NERC Reliability Standards TOP-003 and IRO-010. The SDT used these references to drive the identification of sensitive BES data and chose to base the CIP-012 requirements on the Real-time data specification elements in these standards. This approach provides consistent scoping of identified data, and does not require each entity to devise its own list or inventory of this data. Many entities are required to provide this data

[2] NIST Special Publication 800-53A, Revision 4, page B-3
[3] NIST Special Publication 800-53A, Revision 4, page B-6

under agreements executed with their RC, BA or TOP. The SDT asserts that typically the RC, BA or TOP will identify all data requiring protection for CIP-012-1 through the TOP-003 and IRO-010 Reliability Standards. However, the SDT noted that there may be special instances during which Real-time Assessment or Real-time ~~Monitoring~~ monitoring data is not identified by the RC, BA, or TOP. This would include data that may be exchanged between a Responsible Entity's primary and backup Control Center.

Identification of Where Security Protection is Applied by the Responsible Entity

The SDT noted the need for a Responsible Entity to identify where it will apply protection for applicable data. The SDT did not specify the location where CIP-012 security protection must be applied to provide latitude for Responsible Entities to implement the security controls in a manner best fitting their individual circumstances. This latitude ensures entities can still take advantage of security measures, such as deep packet inspection implemented at or near the EAP when ESPs are present, while maintaining the capability to protect the applicable data being transmitted between Control Centers.

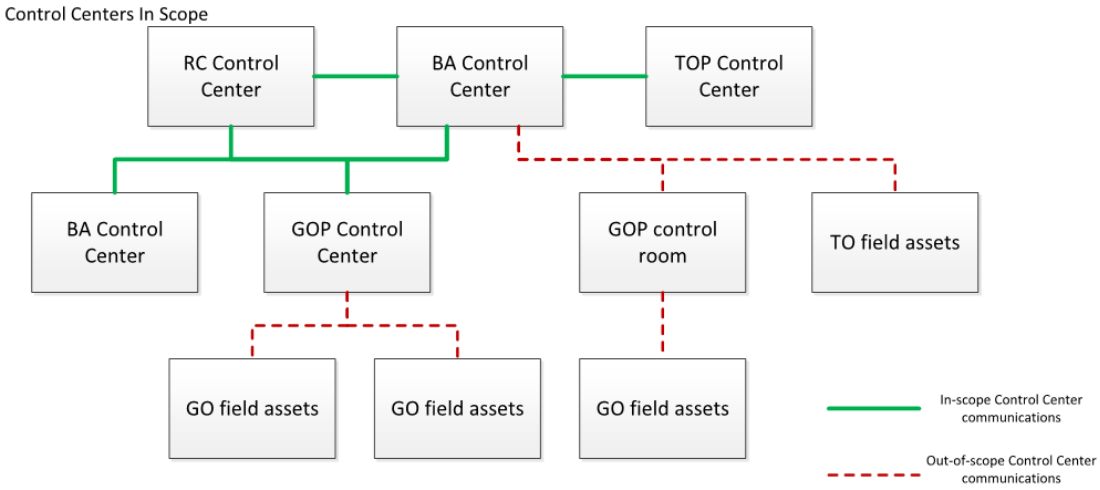
The SDT also recognizes that CIP-012 security protection may be applied to a Cyber Asset that is not an identified BES Cyber Asset or EACMS. The identification of the Cyber Asset as the location where security protection is applied does not expand the scope of Cyber Assets identified as applicable under Cyber Security Standards CIP-002 through CIP-011.

The SDT understands that in data exchanges between Control Centers, a single entity may not be responsible for both ends of the communication link. The SDT intends for a Responsible Entity to identify only where it applied security protection. The Responsible Entity should not be held accountable for identifying where a neighboring entity applied security protection at the neighboring entity's facility. A Responsible Entity, however, may decide to take responsibility for both ends of a communication link. For example, it may place a router in a neighboring entity's data center. In a scenario like this, where a Responsible Entity has taken responsibility for applying security protection on both ends of the communication link, the Responsible Entity should identify where it applied security protection at both ends of the link. The SDT intends for there to be alignment between the identification of where security protection is applied in CIP-012 R1, Part 1.2 and the identification of Responsible Entity responsibilities in CIP-012 R1, Part 1.3.

Control Center Ownership

The requirements address protection for Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers owned by a single Responsible Entity. They also cover the applicable data transmitted between Control Centers owned by two or more separate Responsible Entities. Unlike protection between a single Responsible Entity's Control Centers, applying protection between Control Centers owned by more than one Responsible Entity requires additional coordination. The requirements do not explicitly require formal agreements between Responsible Entities partnering for protection of applicable data. It is strongly recommended, however, that these partnering entities develop agreements, or use existing ones, to define responsibilities to ensure the security objective is met. An example noted in FERC Order No. 822 Paragraph 59 is, "if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system."

As an example, the reference model below shows some of the data transmissions between Control Centers that a Responsible Entity should consider to be in-scope. The example does not include all possible scenarios. The solid green lines are in-scope communications. The dashed red lines are out-of-scope communications.



This reference model is an example and does not include all possible scenarios.

References

Here are several references to assist entities in developing plan(s) for protection of communication links:

- NIST Special Publication 800-53A, Revision 4: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST Special Publication 800-82: Guide to Industrial Control Systems (ICS) Security
- NIST Special Publication 800-175B: Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
- NIST Special Publication 800-47: Security Guide for Interconnecting Information Technology Systems

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Team Preliminary Recommendation

FAC-008-3 Facility Ratings

Executive Summary

The Review Team completed a comprehensive review of FAC-008-3 – Facility Ratings. The team found the standard is sufficient to protect reliability and meets its reliability objective; however, there may be future opportunity to improve minor clarity and consistency issues. The observations and recommendations of the Review Team are documented below.

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 (ANSI) 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 (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM)[2], the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (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 SPM.

[1] American National Standards Institute website: https://www.ansi.org/ http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee A regional representative will be included on the Standing Review Team. The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	The SC will appoint stakeholder SMEs 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.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The SC will appoint stakeholder SMEs 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 re-affirming 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]Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
[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.

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 Al McMeekin.

Applicable Reliability Standard: FAC-008-3 Facility Ratings
Team Members (include name and organization): 1. William Winters, Consolidated Edison Company of NY, Inc. 2. Josephine Daggett, Western Area Power Administration 3. Jeff Gruseck, Duke Energy 4. Kimberly Jursic, Georgia Power Company 5. Mario Kiresich, Southern California Edison 6. Hassib El Murdea, Ontario Power Generation 7. Brett Riedl, ComEd 8. Yaoyu Wang, American Electric Power
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 obvious 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: **See Attachment 4.**

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 (RAI) and FERC and NERC guidelines?

   ☒ Yes
   ☐ No

   If you answered "No," please identify which elements require revision, and why:

   See Attachment 4.

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:

   See Attachment 4.

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?

   ☒ Yes
   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

Response: The standard is applicable to GOs. There is no ambiguity about the inclusion of generator Interconnection Facilities.

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

Response: Not applicable.

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), 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.)

Response: Not applicable.

9. **Results-Based Standard (RBS):** Is the Reliability Standard drafted as a RBS?

☒ 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

[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

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: **See Attachment 4.**

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:
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:

12. **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:

13. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes
☐ No

If not, please summarize your assessment:

14. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes
☐ No

If not, please summarize your assessment:

15. **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, or 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 SC.

Preliminary Recommendation *(to be completed by the Review Team after its review and prior to posting the results of the review for industry comment)*

☐ RE-AFFIRM *(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 retirement 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)*:

Preliminary Recommendation posted for industry comment *(date):* 10/30/2017

Final Recommendation ***(to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation)***

☐ RE-AFFIRM *(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 retirement 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.

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.

[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.

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

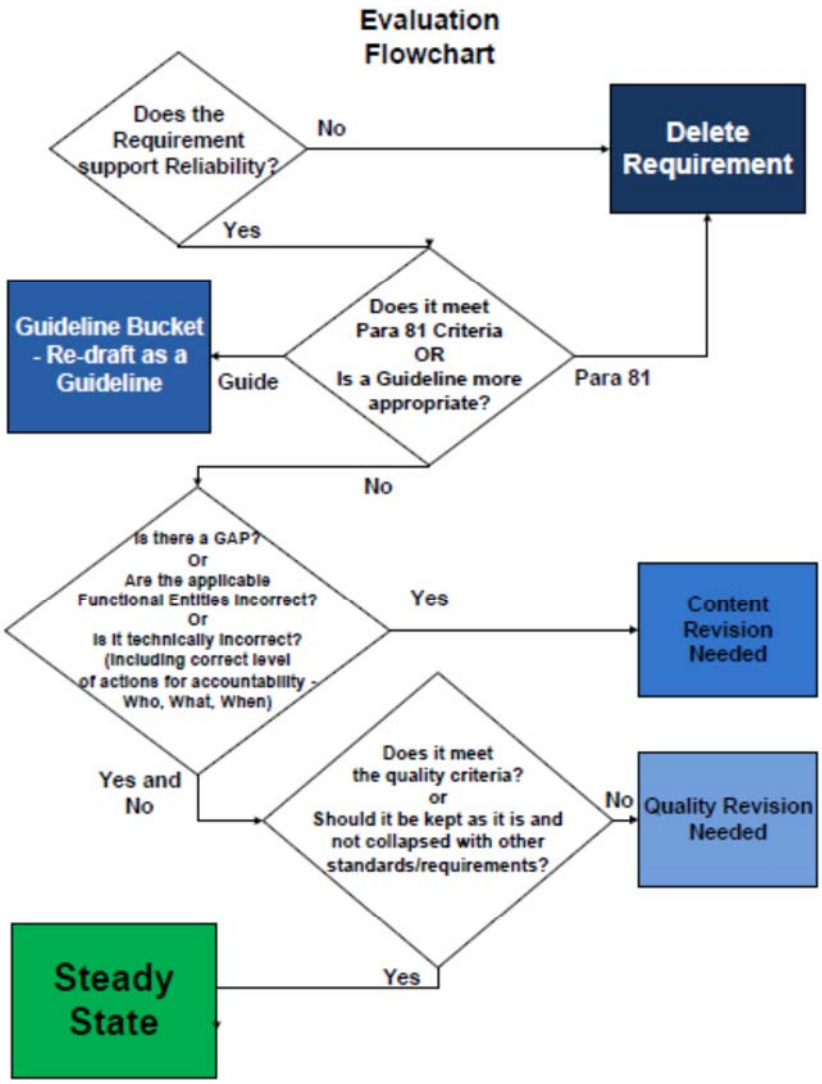


Figure 1: Evaluation Flow Chart

Attachment 4: Potential Revisions/Corrections

The Review Team consolidated a number of potential improvements that could be implemented by a drafting team should the standard be opened for revision. If you provide comments during the posting period regarding one of the team's observations, please reference the particular observation.

1) Paragraph 81 (None)

2) Clarity

   A. Requirement R1 and Requirement R2:
   Future consideration could be given to combining the requirements. The provision for Generator Owners to use documentation (e.g., design criteria or test data) for establishing Facility Ratings could be incorporated into the Facility Ratings methodology specified in Requirement R2.

   B. Requirement R2 and Requirement R3:
   Consider reordering the Parts of Requirements R2 and R3 in a more logical order, perhaps hierarchically from Facility Ratings to Equipment Ratings.

   C. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider replacing the term 'methodology' in Requirement R2, Part 2.1 and Requirement R3, Part 3.1 with the term 'methods' to prevent confusion. Using the term 'methodology' twice implies that two different documents (rather than a single document for Facility Ratings) are required.

   D. Requirement R2, Part 2.2 and Requirement R3, Part 3.2:
   Consider removing the word 'methods' as the 'methodology' is already addressed in Requirement R2, Part 2.1 and Requirement R3, Part 3.1. Parts 2.2 and 3.2 should be limited to the assumptions and design criteria.

   E. Requirement R2, Part 2.2.1 and Requirement R3, Part 3.2.1:
   Consider revising Parts 2.2.1 and 3.2.1 to state: "Industry standard(s) for establishing Equipment Ratings" since 'methodology' is already addressed in Parts 2.1 and 3.1.

   F. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider deleting the main body of Parts 2.4 and 3.4 as they seem redundant to Parts 2.1 and 3.1, respectively. Parts 2.4.1, 2.4.2, 3.4.1 and 3.4.2 are sufficiently independent and clear enough to be Parts 2.4, 2.5, 3.4, and 3.5, respectively.

   G. Requirement R7 and Requirement R8, Part 8.1:
   Consider replacing 'as scheduled by … requesting entities' with "on a mutually agreed upon schedule". According to the current language, a requesting entity could propose an unreasonable schedule which could impose a compliance burden on the provider.

3) Definitions (None)

4) Compliance Elements

   A. High VSLs Requirements R2 and R3:

Since Requirements R2 and R3 are identical, consider revising the language of the High VSLs to be identical.

5) Consistency with other Reliability Standards

   A. Requirement R1, Part 1.1:
   Consider adding the term 'Facility(ies)' after 'generator' to be consistent with the term 'Generator Facility(ies)' in the main body of Requirement R1.

   B. Requirement R1, Part 1.1, Requirement R2, Part 2.1, Requirement R3, Part 3.1:
   Consider making the language (of the three bullets) referencing industry groups (e.g. IEEE, ANSI, CIGRE) consistent across all requirements.

   C. Requirement R1, Part 1.2, Requirement R2, Part 2.3, Requirement R3, Part 3.3:
   Consider using "do not exceed" rather than "respect" for consistency and additional clarity.

   D. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider using the NERC Glossary term "Equipment Ratings" rather than "Ratings of the equipment that comprise the Facility".

   E. Measures M4 and M5:
   Update the text "(Retirement approved by NERC BOT pending applicable regulatory approval.)" to reflect FERC approval of retirement as stated with Requirements R4 and R5: "(Retirement approved by FERC effective January 21, 2014.)"

6) Changes Technology, System Conditions, or other Factors (None)

7) Practicable (None)

8) Consideration of Generator and Transmission Interconnection Facilities (None)

9) Results-Based Standard (RBS) (None)

10) Technical accuracy

   A. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider removing 'shunt compensation devices' from the list of equipment that comprises a Facility. Shunt devices are not series-connected devices. There are no thermal ratings and therefore are not considered in the Facility Rating as limiting equipment. The RSAW correctly focuses the auditor's attention on series-connected devices.

11) Functional Model (None)

12) Applicability (None)

13) Reliability Gaps (None)

14) Technical Quality (None)

15) Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16) Related Regional Reliability Standards (None)

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Standards Announcement

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards

Periodic Review Team Nomination Period Open through May 15, 2017

Now Available

Nominations are being sought for periodic review team members through **8 p.m. Eastern, Monday, May 15, 2017**.

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 Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 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 Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability Standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the Reliability Standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities			

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by ~~either the Distribution Provider (DP), the Balancing Authority (BA), or~~ the appropriate functional ~~applicable~~ entity. ~~Additionally, t~~The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability ~~Section~~ section of PRC-005 and PRC-006 per NERC registration criteria.~~; and review the Applicability sections of PRC-004 and PRC-008 and revise, as appropriate, to add UFLS-only DPs.~~ Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally, PRC-005~~-1.1b~~ and PRC-006~~-003~~ will be updated to add UFLS-only DP to the Applicability ~~Sections~~sections. ~~and a review of the Applicability Sections of PRC-004-5(i) and PRC-008-0 to add, as appropriate, UFLS-only DP to align with the post-RBR registration impacts.~~ 3. Initiatives that can address RBR updates through the periodic review process. ~~-~~The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions. ~~This would include the INT-004-3.1 and NUC-001-3 standards. Rather than the Project 2017-07 making the revisions the SDT could coordinate with the periodic review teams currently reviewing INT-004-3.1 and NUC-001-3 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and Standard Drafting Team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

Requested information
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
None
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

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

Market Interface Principles	
Does the proposed standard development project 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

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NPCC and SERC	~~UFLS-only DP will be added to the Applicability Section of PRC-006 and will create a variance of the following two~~ Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	~~January X~~December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Canadian-specific Revision to proposed standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events)		
Date Submitted:	February 27, 2018		
SAR Requester			
Name:	Helen Lainis (IESO) and Payam Farahbakhsh (Hydro One)		
Organization:	Canadian Electricity Association ("CEA") Members from Ontario (IESO and Hydro One), with the support of additional CEA Members including Manitoba Hydro, Hydro Québec and SaskPower.		
Telephone:	Helen: 905-855-4106 Payam: 416- 345 - 5484	Email:	Helen: helen.lainis@ieso.ca Payam: Payam.Farahbakhsh@HydroOne.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☒ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The need for this SAR is to enable the option for Canadian Registered Entities to leverage operating experience, observed GMD effects and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events specific to their unique topology. Registered Entities from Ontario, Québec, Manitoba and Saskatchewan have indicated support for a revision to be included in TPL-007-2 as an option for Canadian Registered Entities to pursue. At a minimum, Registered Entities in Ontario (Hydro One and IESO) have indicated that this proposed			

Requested information
revision would be used to define and implement an alternative Benchmark GMD Event and/or Supplemental GMD Event that appropriately reflects their specific geographical and geological characteristics.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal is to enable Canadian Registered Entities to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflects the specific geographical and geological characteristics of the Canadian provinces, including those located on the Canadian Shield, a vast area of igneous rock exhibiting low electrical conductivity, through leveraging ongoing research efforts, operating experience, and observed GMD effects: • Registered Canadian entities from Canadian provinces (most prominently Manitoba, Ontario and Québec) located on the Canadian Shield, are currently working to develop a Benchmark GMD Event and/or Supplemental GMD Event that takes into account their unique topology. • These Canadian Registered Entities have been researching the impact of GMD on their power systems for several years now, and have been collaborating with Natural Resources Canada to collect and analyze Canadian magnetometer data for their respective provinces.
Project Scope (Define the parameters of the proposed project):
Reliability Standard TPL-007-2 should be revised to allow Canadian jurisdictions to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that are different from the ones defined in TPL-007-2 appropriate for a continent wide standard. The Benchmark GMD Event and/or Supplemental GMD Event described in TPL-007-2 should be options to pursue for Canadian Registered Entities for performing GMD Vulnerability Assessments. Implementation of Benchmark GMD Events and/or Supplemental GMD Events by Canadian Registered Entities should be subject to approval by applicable Canadian governmental authority or their agencies.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
NERC has spent a substantial amount of time and effort working with experts across the industry to develop scientifically sound Benchmark GMD Events defined in TPL-007-2 appropriate for a continent wide standard.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
The research and development in this field continues to evolve, and more remains to be learned, new assessment tools need to be developed and assessment models need to be verified. In Canada, there is on-going work being done on this subject. We request that TPL-007-2 provide the flexibility for Canadian jurisdictions to leverage their expertise and to build on their research and on GMD impact assessment methodologies to define alternative Benchmark GMD Events and/or Supplemental GMD Events targeted to their unique topology. The Canadian Shield is a sprawling rock formation that stretches across nearly all of Québec, much of Ontario and Manitoba, the northern portion of Saskatchewan and the northeast corner of Alberta. This geological formation blocks current from being dissipated into the Earth, making these Canadian provinces more susceptible to solar storms. As such, Registered Entities from several Canadian shield provinces have been researching the impact of GMD on the reliable operation of their BES for years. For example, Hydro One Networks Inc., has been conducting this work in Ontario, Manitoba Hydro has been conducting this work in Manitoba and Hydro Québec has been conducted this work in Québec. A list of several technical publications could be provided upon request of the SDT to demonstrate the depth of Hydro One's, Manitoba Hydro's, Hydro Québec's and other jurisdictions' technical research and expertise in modeling and analyzing GMD impacts. These references also describe significant development efforts on tools and operating processes to support planned transmission system performance during GMD events. Natural Resources Canada has published their calculations of extreme value statistics for a 1-50 and 1-100 year geomagnetic storm based on data from 13 Natural Resources Canada geomagnetic observatories, and Natural Resources Canada and Registered Entities from Canadian shield provinces have been collaborating to collect and analyze Canadian magnetometer data for their respective provinces.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost implications of addressing a Benchmark GMD Event and/or Supplemental GMD Event is expected to be more significant for the Canadian shield provinces than for those registered entities in the lower 48 state portion of the United States. Furthermore, any capital investment must be approved by the applicable provincial regulatory authority. Consequently, it is essential that the requirements of the standard appropriately reflect conditions that exist in affected Canadian provinces. To this end, Registered Entities from these provinces are working with Natural Resources Canada and are using their own inputs to develop a Benchmark GMD Event and/or Supplemental GMD Event based on empirical data that will form the basis for seeking approval for any required investments with their respective regulatory authorities.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
Not Applicable

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Canadian Registered Entities that meet the applicability specified in Sections 4.1 and 4.2 of the proposed TPL-007-2 Reliability Standard.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The revision would be used, at a minimum, by IESO and Hydro One to avoid needing to seek remand to TPL-007-2 in Ontario, Canada. Working with CEA, IESO and Hydro One have engaged other Canadian Registered Entities to solicit feedback. Registered entities from Manitoba, Québec and Saskatchewan are supportive of a to TPL-007-2 as an option for Canadian Registered Entities to pursue. No Canadian Entity has voiced opposition to such a revision.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.
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[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	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.

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

2	June 28, 2017	Standards Information Staff	Updated template

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revisions to CIP-008-5 Cyber Security- Incident Reporting and Response Planning		
Date Submitted:	August 6, 2018		
SAR Requester			
Name:	Soo Jin Kim		
Organization:	NERC		
Telephone:	404.831.4765	Email:	Soo.jin.kim@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
On July 19, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 848 in order to augment the mandatory reporting of Cyber Security Incidents.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project will address the directives issued by FERC in Order No. 848 in order to augment mandatory reporting of Cyber Security Incidents, including attempts that might facilitate subsequent efforts to harm the reliable operation of the Bulk Electric System (BES). FERC directed NERC to develop and submit modifications that would "require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMs)." NERC was directed to submit the modifications within 6 months of the effective date of the final order.			

Requested information
Project Scope (Define the parameters of the proposed project):
The Standards Drafting Team (SDT) for Project 2018-02 will address FERC's directives in Order No. 848 that require developing or modifying existing Reliability Standards and associated definitions to augment the reporting of Cyber Security Incidents. The scope of any new reporting requirement will be tailored to provide better information on cyber security threats and vulnerabilities without imposing an undue burden on responsible entities.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The SDT shall address the Order No. 848 directives. The Reliability Standard(s) developed or revised will include the 4 elements outlined by FERC: 1. responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; 2. required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; 3. establish deadlines for filing Cyber Security Incidents that are commensurate with incident severity; and 4. Cyber Security Incident reports should be sent to the Electricity Information Sharing and Analysis Center (E-ISAC) and the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT). With regard to identifying EACMS for reporting purposes, the Commission stated that the reporting threshold should encompass the functions that various electronic access control and monitoring technologies provide. The Commission specified that, at a minimum, those functions must include: 1. authentication; 2. monitoring and logging; 3. access control; 4. interactive remote access; and 5. alerting.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
With regard to the definition of "attempted compromise" for reporting purposes, the Commission stated that it considers attempted compromise to include unauthorized access attempts or other confirmed suspicious activity. With regard to content to be included in each report, the Commission stated that the minimum set of attributes to be reported must include: 1. The the functional impact, where possible to determine, that the Cyber Security Incident achieved or attempted to achieve; 2. the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and 3. the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional cost outside of the time and resources needed to serve on the Standard Drafting Team are expected. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No consensus building has been completed to date.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
Project 2016-02 is currently working on addressing FERC directives and the V5TAG Transition document which include potential modifications to the ESP and EACMS definitions.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

NA

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

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

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NA	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☒ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION 4

Effective TBD

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Section 1.0: Introduction 1

Section 2.0: Elements of a Reliability Standard 4

Section 3.0: Reliability Standards Program Organization 7

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard 11

Section 5.0: Process for Developing a Defined Term 23

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data 25

Section 7.0: Process for Developing an Interpretation ..... 28~~27~~

Section 8.0: Process for Appealing an Action or Inaction ..... 33~~31~~

Section 9.0: Process for Developing a Variance ..... 35~~33~~

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue ..... 37~~35~~

Section 11.0: Process for Approving Supporting Documents ..... 42~~40~~

Section 12.0: Process for Correcting Errata ..... 44~~42~~

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards ..... 45~~43~~

Section 14.0: Public Access to Reliability Standards Information ..... 46~~44~~

Section 15.0: Process for Updating Standard Processes ..... 47~~45~~

Section 16.0: Waiver ..... 48~~46~~

Section 1.0: Introduction

1.1: Authority

This manual is published by the authority of the North American Electric Reliability Corporation ("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 has been incorporated into the NERC Rules of Procedure as Appendix 3A. It provides implementation detail in support of the ~~ERO~~NERC 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. Unless otherwise specified, any period of time that is counted in days shall refer to calendar days.

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~~teams, and the 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~~The United States Federal Energy Regulatory Commission ("FERC") certified NERC as the ERO effective July 2006. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes

NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***

  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***

  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***

  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***

  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***

  The process shall be transparent to the public.

- ***Consideration of views and objections***

  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***

  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***

  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

    - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
    - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***

  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***

  The International System of units is the preferred units of measurement in NERC Reliability ~~Standard.~~ Standards. 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, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System. The term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions). ~~*See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.~~[1]

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.[2] 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.[3] 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

[1] *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

[2] 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.

[3] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

four components: who, 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.[4]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies ~~which entities are assigned reliability requirements. The~~the specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[5]

- ***Measure***: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

[4] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as ~~provide~~provided on the Reliability Standards Resources web page.

[5] 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~~...~~.

- ***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.~~[6] Reliability Standard.[7] Each requirement in each ~~reliability standard~~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~~Reliability Standard, but are not part of the ~~reliability standard~~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.[8]

  - ***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.[9]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.~~

~~***Procedures*:** Procedures to support implementation of the associated Reliability Standard.~~

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes~~, to establish the relevant scope and technical paradigm,~~ and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

~~[6] 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.~~

[7] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of a Reliability Standard and is posted on the NERC web site.

[8] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources ~~Web Page~~web page.

[9] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources ~~Web Page~~web page.

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~~developed 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[10], 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.[11] The composition of the Standards Committee and the election of its members ~~are elected by their respective Segment's stakeholders. The~~ is set forth in Appendix 3B to the NERC Rules of Procedure, *Procedures for Election of Members of the Standards Committee* ~~consists of two members of each of the Segments in the Registered Ballot Body.[12] 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.[13]

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 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)

[10] 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.

[11] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

~~[12] 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.~~

[13] 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.

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,[14] 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~~ , and 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.[15] 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.
- Develops and refines technical documents that aid in the understanding of Reliability Standards.

[14] The Director of Standards may delegate its authority to perform certain responsibilities specified in this manual to another member of the NERC Reliability Standards staff.

[15] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- 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")~~FERC in the United States of America, and where permissible by statute or regulation, the federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO 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~~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[16] 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.

[16] 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.[17]

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.

[17] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

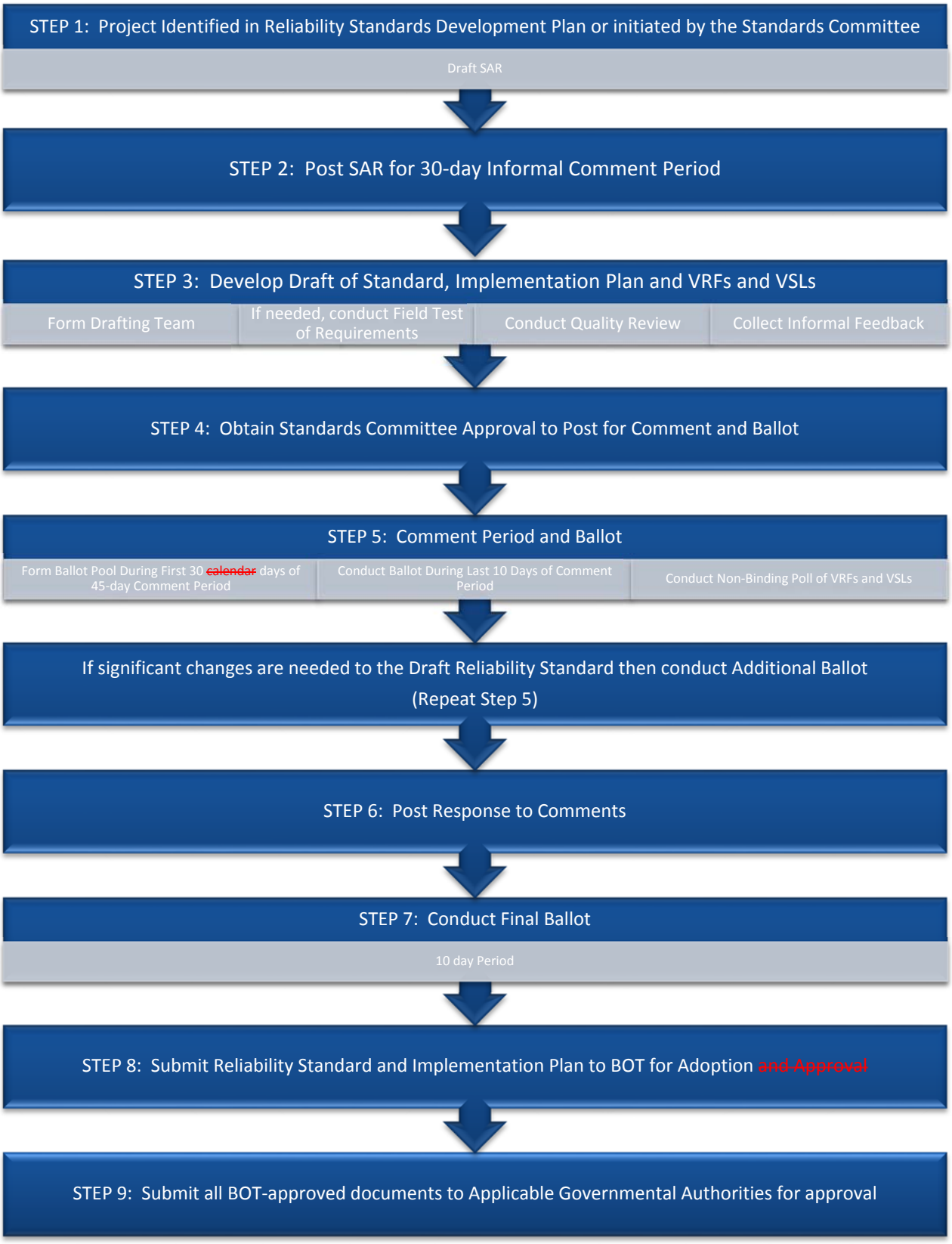


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR~~[18]~~ to the NERC Reliability Standards Staff.[19] 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,*[20] 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.

~~[18] The SAR form can be downloaded from the Reliability Standards Resources web page.~~

[19] The SAR form is available on the Reliability Standards Resources web page.

[20] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

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 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~~ during the public posting period. The drafting team may ~~be~~ address the comments 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 *Ten Benchmarks ~~for~~of an Excellent ~~Standards.~~ Reliability Standard*. 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 *Ten Benchmarks ~~for~~of an Excellent ~~Standards~~Reliability Standard*.

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~~and that meets the quality attributes identified in NERC's *Ten Benchmarks* ~~for~~*of an Excellent* ~~Standards and~~ *Reliability Standard*, with a goal of meeting the 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.~~

The drafting team may, at its discretion, develop one or more supporting technical documents to help explain or facilitate understanding of the draft Reliability Standard, implementation plan, VSL, or VRF. These supporting technical documents may include, among other things: (1) reference documents designed to provide the drafting team's technical rationale, analysis, or explanatory information to support the understanding of the draft Reliability Standard or related element; or (2) white papers designed to explain a technical position or concept underlying the draft Reliability Standard or related element. Such documents may be posted during an informal comment period (Section 4.5) or formal comment period (Section 4.7).

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[21]

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,[22] 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 *Ten Benchmarks* ~~for~~*of an Excellent* ~~Standards~~*Reliability Standard* 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.

[21] 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.

[22] 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.

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.

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 or its designee 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~~authorized deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[23]

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.[24]

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.

[23] 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.

[24] Closing dates may be extended as deemed appropriate by NERC Staff.

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.

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[25] 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[26] 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;

[25] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[26] 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.

- Negative;[27]
- Abstain.

4.12: Consideration of Comments and 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.

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. ~~However, a~~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. 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 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.

~~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.~~

4.13~~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

[27] 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.

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.

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.

~~4.15~~4.14: 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.~~ ~~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.~~

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~~15: 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~~Board shall consider approval of the VRFs and VSLs associated with a ~~reliability standard.~~ 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~~16: 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~~17: 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~~18: 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*[28] ("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.

[28] 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: Process for Conducting Field Tests

While most drafting teams can develop 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 benefit from 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.

A field test is initiated by either a SAR or Reliability Standard drafting team. ~~The drafting team may be supplemented with other individuals based on the required technical expertise needed to support the field test.~~ The drafting team is responsible for developing the field test plan, including the implementation schedule, and ~~for~~ identifying compliance-related issues, such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis (collectively "field test")

- Field tests to validate concepts ~~that support~~supporting the development of Reliability Standards should be conducted~~, to the extent possible,~~ before finalizing the SAR for a project ~~is finalized.~~ .
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team ~~must~~shall work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The ~~field test is conducted by the~~ drafting team shall perform the field test, in coordination with NERC Staff and under the ~~oversight~~supervision of the assigned technical committee, in accordance with an approved field test plan. The drafting team may be assisted by other individuals based on the required expertise needed to support the field test.
- The lead NERC technical committee shall identify potential field test participants.

6.1.1~~.~~: Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan~~,~~;
- the implementation schedule~~,~~; and
- ~~an expectation~~a schedule for providing periodic updates ~~of the~~regarding field test results and analysis ~~of the results~~ to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team ~~must~~shall: (i) first receive approval from the lead NERC technical committee~~. Second, the drafting team must~~; and (ii) then receive approval from the Standards Committee.

The lead NERC technical ~~committee's~~committee shall base its approval ~~shall be based~~ on the technical adequacy of the field test ~~plan~~request. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test ~~plan request. The lead NERC technical committee shall coordinate all entity participation in the field test, such as accepting, adding, and withdrawing individual entities from the field test, as well as coordinating and communicating status of the results of the field test.~~ request.

The Standards Committee's decision to approve the field test ~~plan~~ request shall be based ~~solely~~ on ~~whether the Standards Committee, by majority vote, agrees or disagrees with the lead NERC technical committee's~~: (i) an affirmative recommendation~~. If the Standards Committee disagrees with the lead NERC technical committee's recommendation, the Standards Committee shall inform~~ from the lead NERC technical committee ~~with~~regarding the field test plan; and (ii) the Standard Committee's approval of the implementation schedule and the periodic update

schedule. If the Standards Committee rejects the field test request, the Standards Committee shall provide an explanation of the ~~basis for the~~ decision to the lead NERC technical committee.

6.1.2: Compliance Waivers

~~After approval of the field test, the drafting team may request~~Compliance waivers ~~of compliance~~may be required for Registered Entities ~~for field test participants~~ that would be rendered incapable of complying with the Requirement(s) of a currently ~~-~~enforceable Reliability Standard due to their participation in the field test. The NERC Compliance Monitoring and Enforcement Program Staff shall determine whether to approve ~~the~~ any such ~~requested~~ compliance waivers and shall be responsible for approving any modifications or terminations to approved waivers that may become necessary following the start of the field test. ~~The NERC Reliability Standards~~ Staff shall ~~inform~~ notify the affected Registered Entities of all compliance waiver determinations. ~~.~~

6.1.3: Field Test Suspension for Reliability Concerns

During the field test, if NERC or the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System, NERC or the lead NERC technical committee shall:

- ~~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;~~; and
- ~~the~~if NERC or the lead technical committee is of the opinion a modification to the field test is necessary, provide a technical justification to the drafting team.

The Standards Committee, with the assistance of NERC Staff, shall:

- document the cessation or modification of the field test; and
- ~~the Standards Committee, with the assistance of NERC Staff, shall~~ notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as ~~continuance~~continuing or ~~cessation of~~terminating waivers, where applicable (see Section 6.1.2).

Prior to modifying the field test or restarting the field test ~~being restarted~~ after it has been stopped, the drafting team ~~must~~shall resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.~~3~~4: Continuing, Modifying, or Terminating a Field Test

If the drafting team ~~concludes~~determines that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, ~~the drafting team~~it shall provide ~~a recommendation to either continue (including extending the duration of the field test beyond the period of standard development), modify, or terminate the field test~~ to the lead NERC technical committee and the chair of the Standards Committee a recommendation to continue, modify, or terminate the field test. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test~~,~~ and thereafter~~,~~ provide notice to the ~~chair of the~~ Standards Committee chair of its ~~selection.~~decision. The Standards Committee shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as continuing or terminating waivers (see Section 6.1.2).

If the duration of the field test is extended beyond the period of standard development, NERC Staff shall post the preliminary report and results ~~shall be publicly posted~~ on the NERC web site prior to the final ballot of the Reliability Standard.

6.2: Communication and Coordination for All Types of Field Tests

~~After approval of the field test, the drafting team may request waivers of compliance for field test participants that would be rendered incapable of complying with the Requirement(s) of a currently enforceable Reliability Standard due to their participation. The NERC Compliance Monitoring and Enforcement Program Staff shall determine whether to approve the requested waivers and shall be responsible for approving any modifications or terminations that may become necessary following the start of the field test. The NERC Reliability 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 Board of Trustees of the pending field test, the expected duration, and any requested compliance waivers ~~of compliance for Registered Entities~~.

During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either a preliminary report of the results of the field test to date, if the field test will continue beyond standard development, or a final report if the field test has been completed. The chair of the Standards Committee shall keep the Board of Trustees informed.

The approved field test plan and any modifications thereto, along with all field test reports and results, shall be publicly posted on the NERC web site. ~~This posting shall include the~~ The participant list shall also be posted, unless ~~it is determined that~~ posting this list would present confidentiality or other concerns.

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.

7.1: Valid Interpretation Criteria

~~An~~A valid Interpretation may only clarify or explain the meaning of the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any ~~attachment~~ referenced ~~in the Requirement. The~~attachment. A valid Interpretation may not alter the scope or ~~the~~ language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an Interpretation

The entity requesting ~~the~~an Interpretation shall submit a *Request for Interpretation* form[29] to ~~the~~ NERC ~~Reliability Standards~~ Staff explaining the clarification ~~required~~or explanation requested, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. ~~NERC Reliability Standards and Legal~~NERC Staff shall review the request for Interpretation to determine whether it meets the ~~requirements~~criteria for a valid Interpretation. Based on this review, NERC Staff shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request. NERC Staff shall periodically communicate to the Standards Committee the status of all Interpretation requests that are pending resolution.

7.2.1: Rejection of an Interpretation Request

~~A~~ The Standards Committee may reject a request for Interpretation ~~may be rejected~~ in the following circumstances:

- ~~Where the~~The request seeks approval of a particular compliance approach.[30]
- ~~Where the~~The issue can be addressed by incorporating the issue into an existing ~~or future~~ standard development project or a project contemplated in a published development plan.
- ~~Where the~~The request seeks clarification or explanation of any element of a Reliability Standard other than a Requirement or referenced attachment.
- ~~Where the~~The issue has already been addressed in the record.[31]
- ~~Where the~~The request identifies an issue and proposes the development of a new or modified Reliability Standard (such issues should be addressed via submission of a SAR).
- ~~Where the~~The request seeks to ~~expand~~alter the scope of a Reliability Standard.
- ~~Where the~~The meaning of a Reliability Standard is clear and evident by inspection or the plain ~~on its face.~~ words that are written.

[29] The *Request for Interpretation* form is posted on the NERC Standards web page.

[30] Requests that ~~contain~~seek approval of specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

[31] The "record" is generally understood to refer to the record of development, regulatory approval record, or other materials developed to support the development or approval of a Reliability Standard.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the rejection to the entity requesting the Interpretation within 10 business days of the decision to reject.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, ~~the Standards Committee~~ it shall authorize NERC ~~Reliability Standards~~ Staff to assemble an Interpretation drafting team for approval by the Standards Committee with the relevant expertise to address the request.

7.2.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a draft Interpretation ~~addressing the request~~, consistent with Section 7.1. Interpretations shall be developed in accordance with the following process:

- NERC ~~Reliability Standards staff~~Staff shall review the draft Interpretation to determine whether it ~~has met~~meets the ~~requirements~~criteria for a valid Interpretation and ~~to~~shall provide ~~a recommendation~~ to the Standards Committee ~~whether~~a recommendation to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after ~~review of~~reviewing the ~~Staff~~ recommendation, ~~may~~shall determine whether to authorize posting of the draft Interpretation for comment and ballot.
- Interpretations shall be balloted in the same manner as Reliability Standards (*see* Section 4.0~~), with the following exceptions:~~).

  - ~~Interpretations shall be posted for a 30-day informal comment period. The Interpretation drafting team is not required to respond in writing to comments submitted during this comment period.~~
  - ~~The NERC Reliability Standards Staff shall establish a ballot pool during the first 20 days of the 30-day informal comment period.~~
  - ~~The ballot window shall take place during the last 10 calendar days of the 30-day informal comment period.~~
  - ~~Final Ballots shall not be conducted for Interpretations. An Interpretation shall be deemed approved by the ballot pool following the first ballot in which the necessary quorum and sufficient affirmative votes are obtained.~~

If the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic criteria for what constitutes a valid Interpretation (*see* Section 7.1), 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 in writing and the disposition of the Interpretation shall be posted.

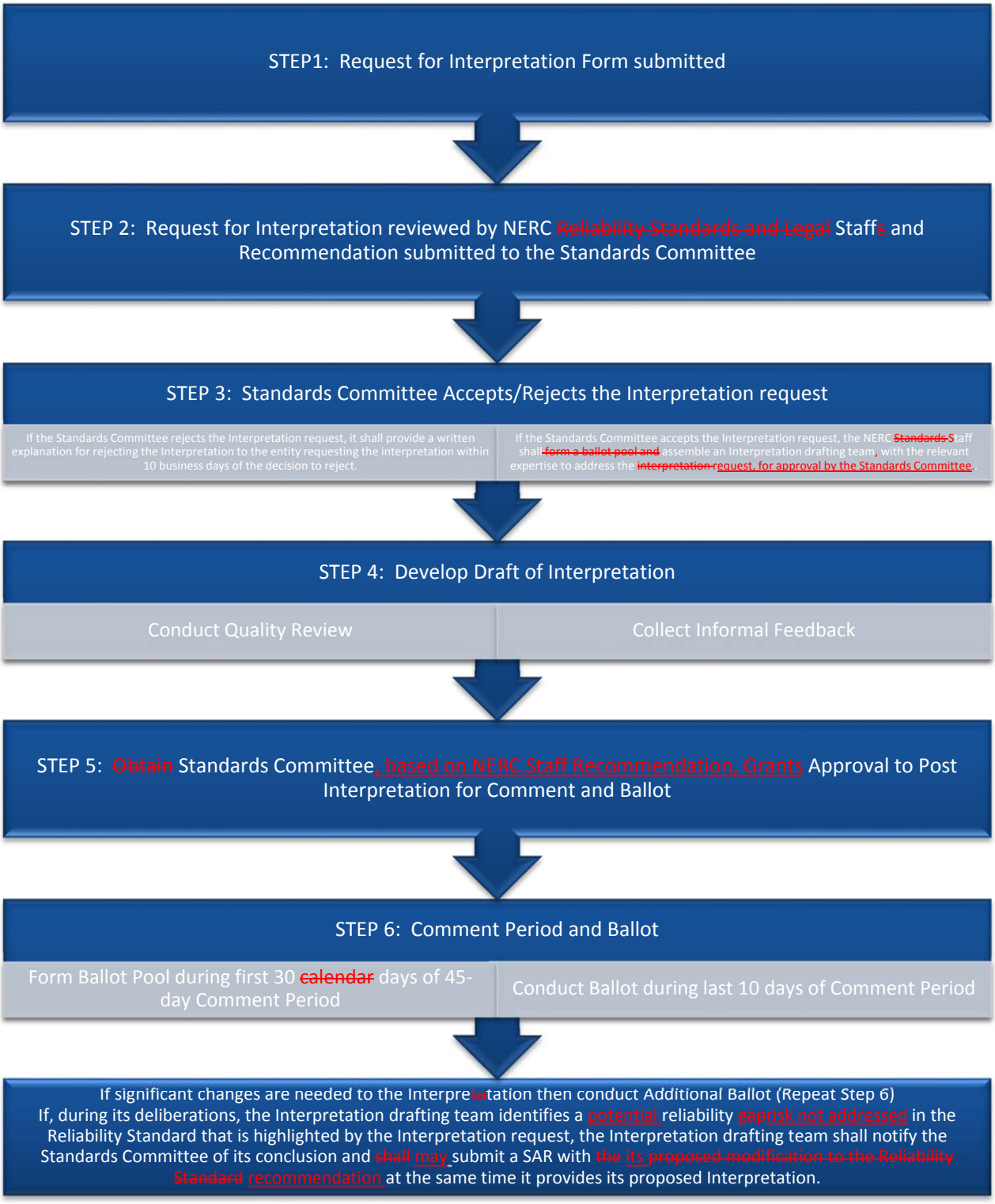
If, during its deliberations, the Interpretation drafting team identifies a potential reliability ~~related deficiency~~ risk not addressed in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with its recommendation at the same time it provides its proposed Interpretation.

If ~~approved by~~ the ballot pool approves the Interpretation, NERC Staff shall review ~~the final Interpretation~~ it to determine whether it ~~has met~~meets the ~~requirements~~criteria for a valid Interpretation and shall make a recommendation to the NERC Board of Trustees regarding adoption.

If an Interpretation drafting team recommends ~~a modification to~~modifying a Reliability Standard ~~as part of~~based on its work in developing ~~an~~the Interpretation, the Board of Trustees shall be notified of this recommendation at the time the Interpretation is submitted for adoption. Following Board of Trustees adoption, the Interpretation shall be

filed with the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable Governmental Authorities.[32] The Interpretation shall stand until ~~the Interpretation~~it 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.

[32] NERC will maintain a record of all ~~interpretations~~Interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC ~~Reliability Standards and Legal~~ Staff~~s~~ and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC ~~Standards~~ Staff shall ~~form a ballot pool and~~ assemble an Interpretation drafting team, with the relevant expertise to address the ~~interpretation~~ request, for approval by the Standards Committee..
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: ~~Obtain~~ Standards Committee, based on NERC Staff Recommendation, Grants Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 ~~calendar~~ days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpre~~ta~~tation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a potential reliability ~~gap~~risk not addressed 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~~ may submit a SAR with ~~the~~ its ~~proposed modification to the Reliability Standard~~ recommendation at the same time it provides its proposed Interpretation.

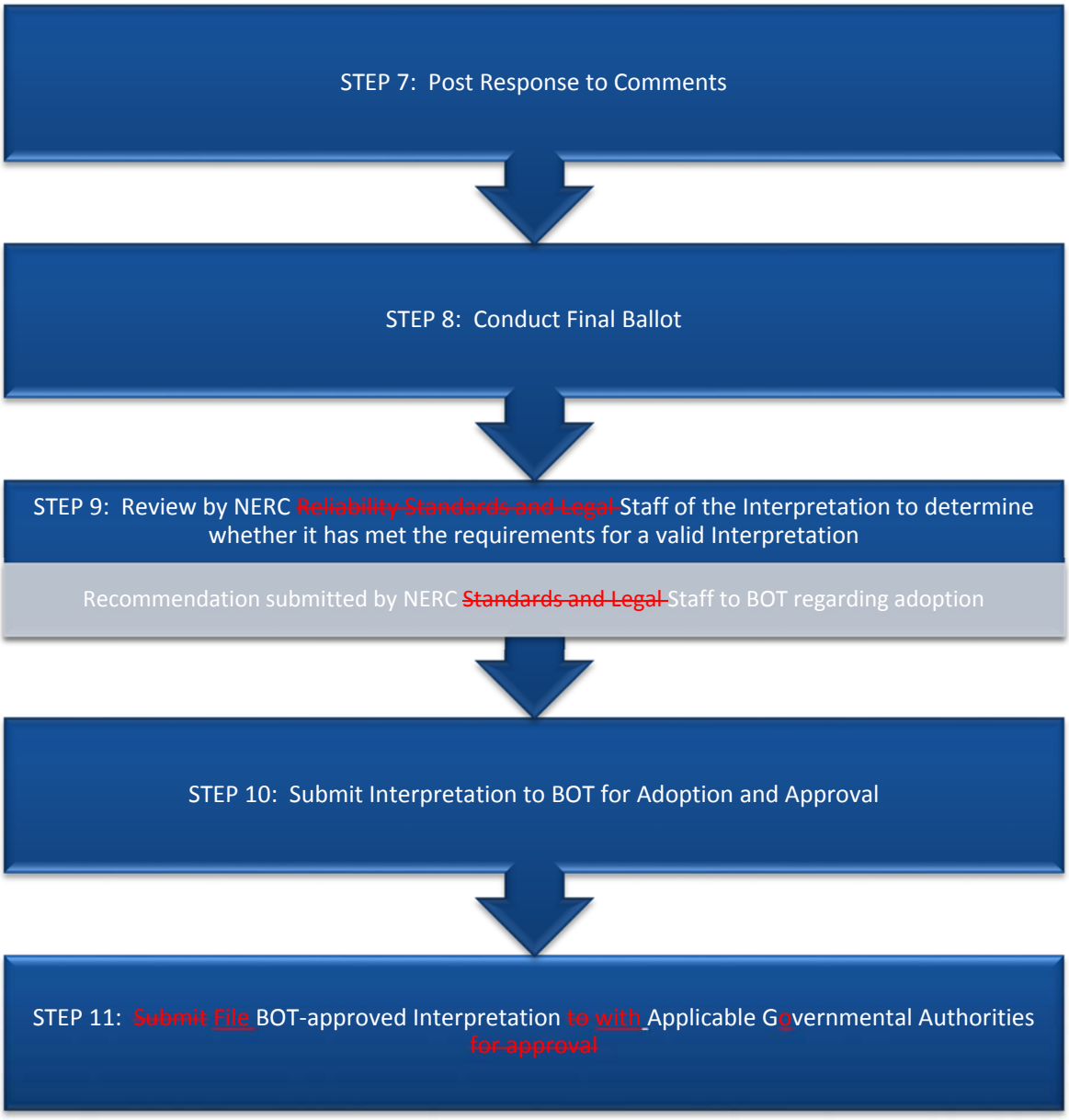


FIGURE 2: Process for Developing an Interpretation

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 or its designee 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.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

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 or its designee 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~~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.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

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[33] 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.

Where a Regional Entity is not organized on an Interconnection-wide basis, but a Variance is proposed to apply to Registered Entities within an Interconnection wholly contained in that Regional Entity's footprint, the Variance may be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and

[33] 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.

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.[34]

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~~confidentiality 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

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

[34] 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.

their organizations that have signed confidentiality agreements with NERC.[35] 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.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

The following flowchart illustrates the process for developing a Reliability Standard responsive to an imminent, confidential issue:

[35] 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.

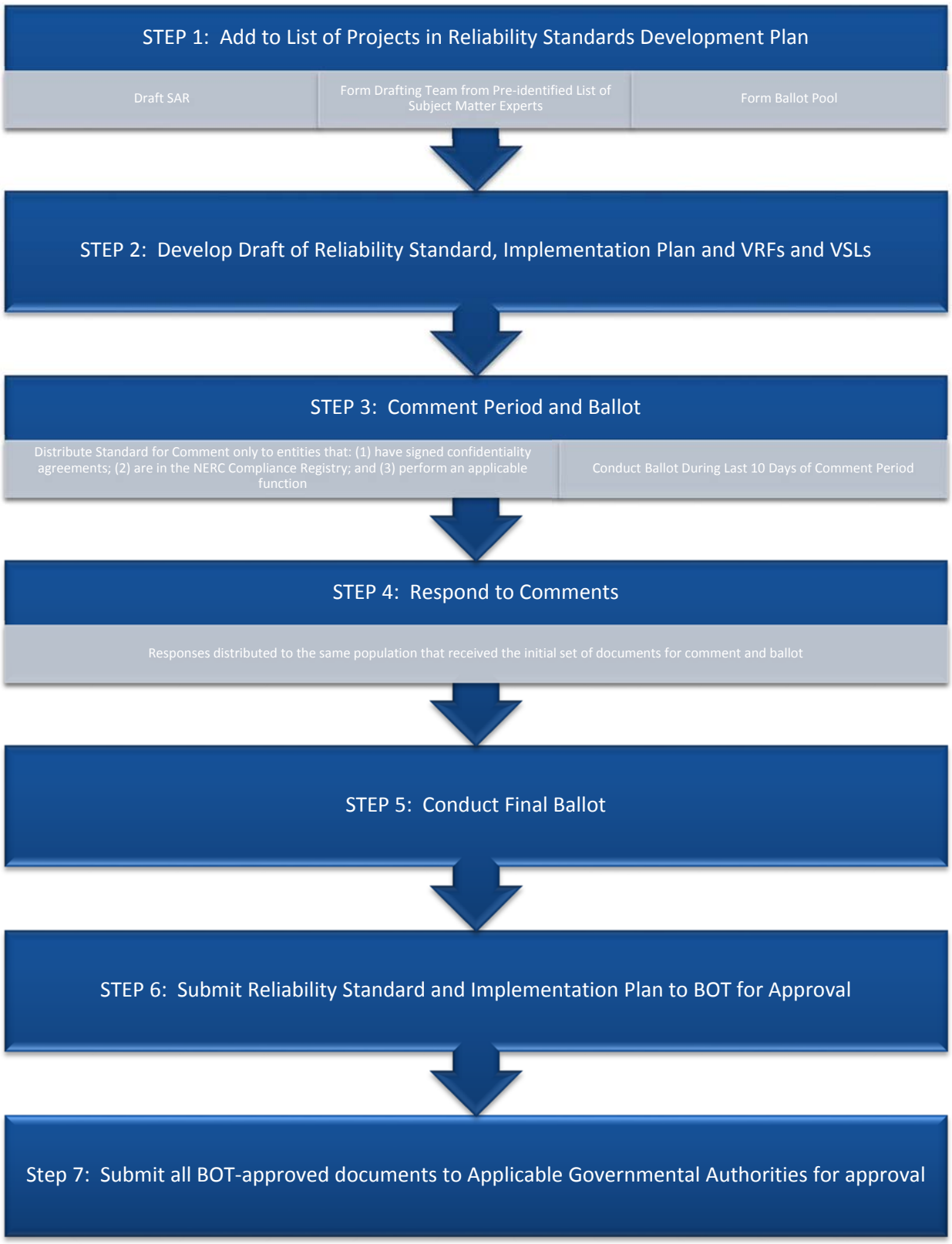


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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~~confidentiality 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.[36] 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.

[36] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

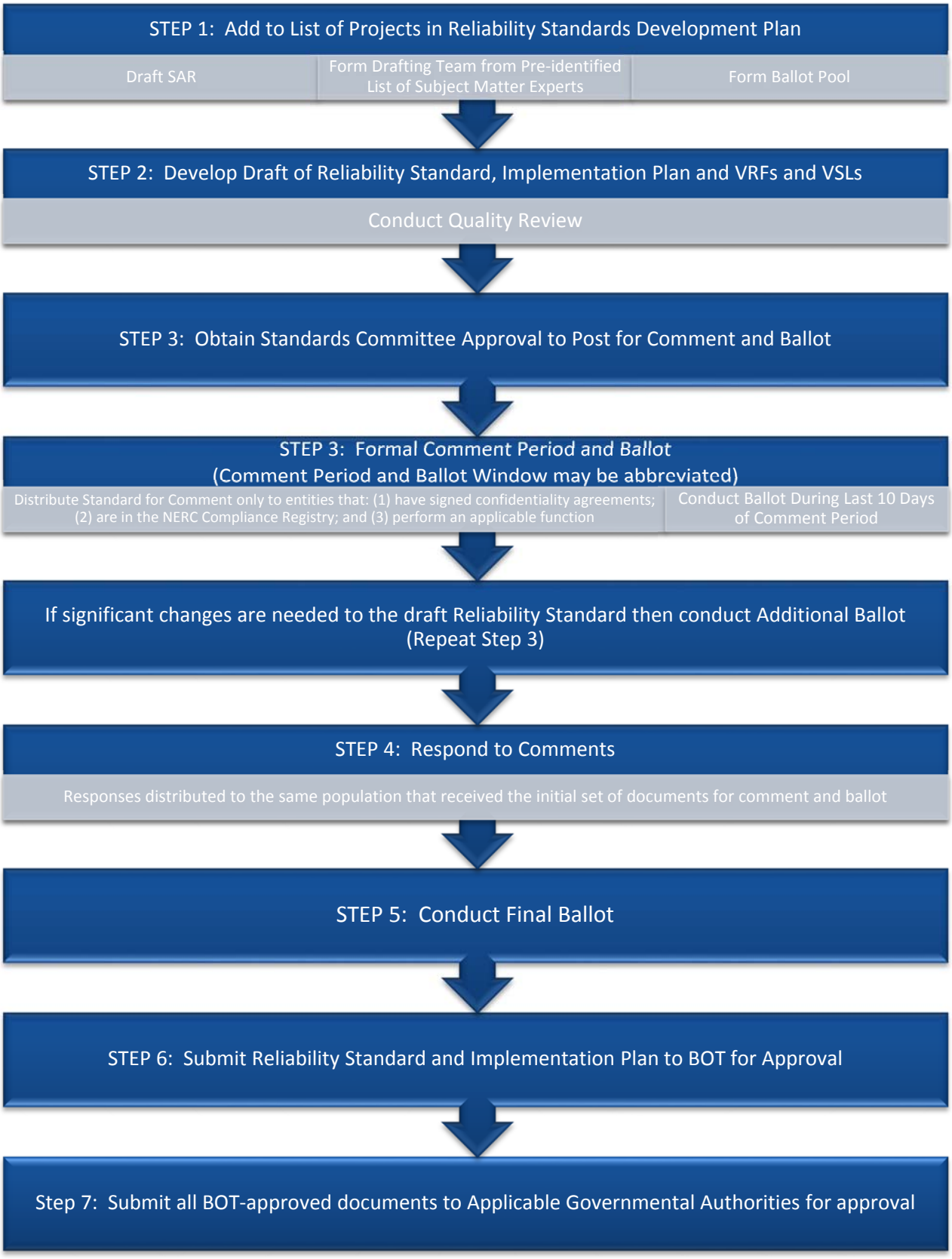


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for ~~Approving~~Posting Supporting Technical Documents Alongside an Approved Reliability Standard

The NERC Standards Committee oversees the development and approval of technical documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. Supporting technical documents may explain or facilitate understanding of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any mandatory Requirements ~~that are mandatory~~ shall be incorporated into the Reliability Standard in the Reliability Standard development process.

This Section provides the ~~mechanism~~process by which any stakeholder may propose a supporting technical document to an approved Reliability Standard. The process outlined in this section is designed so ~~that~~ each supporting document receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting technical document to an approved Reliability Standard.

During the standard development process, standard drafting teams may develop and post supporting technical documents to the pertinent project page, in accordance with Section 4.0. Following approval of the Reliability Standard, those documents may be posted alongside the standard without requiring separate Standards Committee authorization under this Section.

11.1: Types of Supporting Technical Documents

The types of supporting technical documents that may be approved for posting alongside an approved Reliability Standard under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding of an approved Reliability Standard.
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document cannot establish new Requirements or modify Requirements in any existing Reliability Standard.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or a Reference document.

Documents that contain specific compliance approaches or examples ~~of compliance. Such~~are not considered supporting technical documents ~~would be developed in accordance with the applicable NERC Compliance Monitoring and Enforcement Program process.~~under this Section.

11.2: Process for Proposing and Evaluating Supporting Technical Documents

Proposals for supporting technical documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting technical document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting technical document meets the following ~~three~~ criteria:

1. the document is a type of supporting technical document subject to this Section, as described in Section 11.1;
2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

~~Where~~If NERC Staff determines that the proposed supporting technical document ~~has met the~~meets all three criteria specified above, NERC Staff shall submit the proposed supporting technical document to the Standards Committee as specified in Section 11.3 below.

~~Where~~If NERC Staff determines that the proposed supporting technical document does not meet the first or second ~~criteria~~criterion specified above, NERC Staff shall notify the submitter, in writing, that the document will not be posted as a supporting technical document under this Section. This notification shall ~~be made in writing with~~include an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of ~~this~~its determination at the next regularly-scheduled Standards Committee meeting~~.~~.

~~Where~~If NERC Staff determines that the proposed supporting technical document meets the first and second criteria, but has not yet received adequate stakeholder review under the third ~~criteria~~criterion, NERC Staff shall make a recommendation to the Standards Committee to authorize ~~the~~ posting ~~of~~ the proposed supporting technical document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless ~~directed otherwise by~~ the Standards Committee~~.~~ directs otherwise. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide them to the submitter for consideration. If the submitter modifies the proposed supporting technical document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient ~~vetting and~~ technical review.

11.3: Approving a Supporting Technical Document

~~Following its determination~~After determining that the proposed supporting technical document ~~has met~~meets the three criteria specified in Section 11.2, NERC Staff shall present the supporting technical document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting technical document with the approved Reliability Standard on the pertinent NERC website page(s).

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~~periodic review~~"~~ of that Reliability Standard.

For a project that is focused solely on the ~~five-year~~periodic 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:

- Submit the revised process or processes for ballot pool approval;
- Repeat the posting for additional inputs after making changes based on comments received;
- Remand the proposal to the sponsor for further work; or
- 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, Interpretation, 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~~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.[37]~~ 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.

~~[37] 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.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION 4

Effective TBD

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Section 1.0: Introduction 1
Section 2.0: Elements of a Reliability Standard 4
Section 3.0: Reliability Standards Program Organization 7
Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard 11
Section 5.0: Process for Developing a Defined Term 23
Section 6.0: Process for Conducting Field Tests 25
Section 7.0: Process for Developing an Interpretation 27
Section 8.0: Process for Appealing an Action or Inaction 31
Section 9.0: Process for Developing a Variance 33
Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue 35
Section 11.0: Process for Posting Supporting Technical Documents Alongside an Approved Reliability Standard 40
Section 12.0: Process for Correcting Errata 42
Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards 43
Section 14.0: Public Access to Reliability Standards Information 44
Section 15.0: Process for Updating Standard Processes 45
Section 16.0: Waiver 46

Section 1.0: Introduction

1.1: Authority

This manual is published by the authority of the North American Electric Reliability Corporation ("NERC") Board of Trustees and has been incorporated into the NERC Rules of Procedure as Appendix 3A. It provides implementation detail in support of the NERC 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. Unless otherwise specified, any period of time that is counted in days shall refer to calendar days.

1.2: Scope

The policies and procedures in this manual shall govern the activities of 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 teams, and the 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. The United States Federal Energy Regulatory Commission ("FERC") certified NERC as the ERO effective July 2006. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes

NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***

  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***

  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***

  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***

  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***

  The process shall be transparent to the public.

- ***Consideration of views and objections***

  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***

  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***

  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

    - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
    - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***

  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***

  The International System of units is the preferred units of measurement in NERC Reliability Standards. 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, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System. The term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions).[1]

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.[2] 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.[3] 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, under what conditions (if any), shall perform what action, to achieve what particular result or outcome.

[1] *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

[2] 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.

[3] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

- **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.[4]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[5]

- ***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

[4] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provided on the Reliability Standards Resources web page.

[5] 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.

violation of a requirement in an approved Reliability Standard.[6] 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.[7]

- ***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.[8]

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.

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 and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

[6] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of a Reliability Standard and is posted on the NERC web site.

[7] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources web page.

[8] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources web page.

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 developed according to 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[9], 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.[10] The composition of the Standards Committee and the election of its members is set forth in Appendix 3B to the NERC Rules of Procedure, *Procedures for Election of Members of 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.[12]

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 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.

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[9] 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.

[10] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[12] 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.

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,[13] 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, Variances, and 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.[14] 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.
- 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.

[13] The Director of Standards may delegate its authority to perform certain responsibilities specified in this manual to another member of the NERC Reliability Standards staff.

[14] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- 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

FERC in the United States of America, and where permissible by statute or regulation, the federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO 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[15] 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.

[15] 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.[16]

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.

[16] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

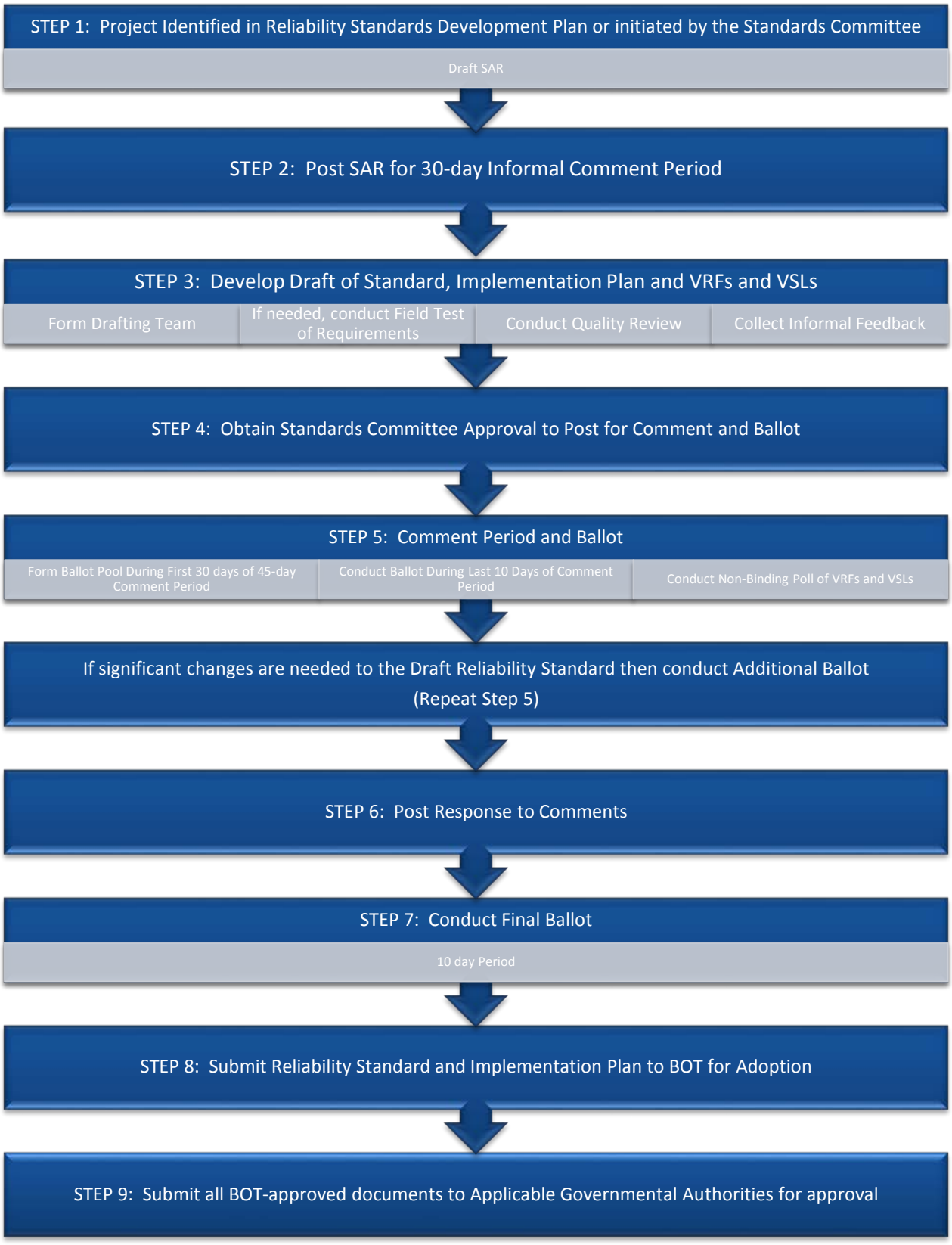


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR to the NERC Reliability Standards Staff.[18] 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,*[19] 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.

[18] The SAR form is available on the Reliability Standards Resources web page.

[19] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

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 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 during the public posting period. The drafting team may address the comments in the form of a summary response addressing each of the issues raised in comments. 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 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 *Ten Benchmarks of an Excellent Reliability Standard*. 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 *Ten Benchmarks of an Excellent Reliability Standard*.

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 and that meets the quality attributes identified in NERC's *Ten Benchmarks of an Excellent Reliability Standard*, with a goal of meeting the criteria for governmental approval.

The drafting team may, at its discretion, develop one or more supporting technical documents to help explain or facilitate understanding of the draft Reliability Standard, implementation plan, VSL, or VRF. These supporting technical documents may include, among other things: (1) reference documents designed to provide the drafting team's technical rationale, analysis, or explanatory information to support the understanding of the draft Reliability Standard or related element; or (2) white papers designed to explain a technical position or concept underlying the draft Reliability Standard or related element. Such documents may be posted during an informal comment period (Section 4.5) or formal comment period (Section 4.7).

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 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[20]

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,[21] 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 *Ten Benchmarks of an Excellent Reliability Standard* 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.

[20] 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.

[21] 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.

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.

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 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 or its designee 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 authorized deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[22]

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 days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 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.[23]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 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.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

[22] 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.

[23] Closing dates may be extended as deemed appropriate by NERC Staff.

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[24] 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[25] 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;[26]
- Abstain.

[24] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[25] 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.

[26] 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 and 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.

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-day public comment period and ballot. 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. 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 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.

4.13: 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.

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.

4.14: Final Ballot Results

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.

4.15: 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.

4.16: 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.

4.17: 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.

4.18: 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*[27] ("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.

[27] 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: Process for Conducting Field Tests

While most drafting teams can develop 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 benefit from 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.

A field test is initiated by either a SAR or Reliability Standard drafting team. The drafting team is responsible for developing the field test plan, including the implementation schedule, and identifying compliance-related issues, such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis (collectively "field test")

- Field tests to validate concepts supporting the development of Reliability Standards should be conducted before finalizing the SAR for a project.
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team shall work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The drafting team shall perform the field test, in coordination with NERC Staff and under the supervision of the assigned technical committee, in accordance with an approved field test plan. The drafting team may be assisted by other individuals based on the required expertise needed to support the field test.
- The lead NERC technical committee shall identify potential field test participants.

6.1.1: Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan;
- the implementation schedule; and
- a schedule for providing periodic updates regarding field test results and analysis to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team shall: (i) first receive approval from the lead NERC technical committee; and (ii) then receive approval from the Standards Committee.

The lead NERC technical committee shall base its approval on the technical adequacy of the field test request. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test request.

The Standards Committee's decision to approve the field test request shall be based on: (i) an affirmative recommendation from the lead NERC technical committee regarding the field test plan; and (ii) the Standard Committee's approval of the implementation schedule and the periodic update schedule. If the Standards Committee rejects the field test request, the Standards Committee shall provide an explanation of the decision to the lead NERC technical committee.

6.1.2: Compliance Waivers

Compliance waivers may be required for Registered Entities that would be rendered incapable of complying with the Requirement(s) of a currently-enforceable Reliability Standard due to their participation in the field test. The NERC Compliance Monitoring and Enforcement Program Staff shall determine whether to approve any such compliance

waivers and shall be responsible for approving any modifications or terminations to approved waivers that may become necessary in the course of conducting the field test. Staff shall notify the affected Registered Entities of all compliance waiver determinations.

6.1.3: Field Test Suspension for Reliability Concerns

During the field test, if NERC or the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System, NERC or the lead NERC technical committee shall:

- stop the activity;
- inform the Standards Committee that the activity was stopped; and
- if NERC or the lead technical committee is of the opinion a modification to the field test is necessary, provide a technical justification to the drafting team.

The Standards Committee, with the assistance of NERC Staff, shall:

- document the cessation or modification of the field test; and
- notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as continuing or terminating waivers, where applicable (see Section 6.1.2).

Prior to modifying the field test or restarting the field test after it has been stopped, the drafting team shall resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.4: Continuing, Modifying, or Terminating a Field Test

If the drafting team determines that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, it shall provide to the lead NERC technical committee and the chair of the Standards Committee a recommendation to continue, modify, or terminate the field test. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test and thereafter provide notice to the Standards Committee chair of its decision. The Standards Committee shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as continuing or terminating waivers (see Section 6.1.2).

If the duration of the field test is extended beyond the period of standard development, NERC Staff shall post the preliminary report and results on the NERC web site prior to the final ballot of the Reliability Standard.

Prior to initiating the field test, the Standards Committee chair and the lead NERC technical committee chair shall inform the Board of Trustees of the pending field test, the expected duration, and any requested compliance waivers. During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either: (i) a preliminary report of the field test results of the field test to date, if the field test will continue beyond standard development; or (ii) a final report of the field test results. The Standards Committee chair shall keep the Board of Trustees informed regarding field test status.

The approved field test plan and any modifications thereto, along with all field test reports and results, shall be publicly posted on the NERC web site. The participant list shall also be posted, unless posting this list would present confidentiality or other concerns.

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.

7.1: Valid Interpretation Criteria

A valid Interpretation may only clarify or explain the meaning of the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any referenced attachment. A valid Interpretation may not alter the scope or language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an Interpretation

The entity requesting an Interpretation shall submit a *Request for Interpretation* form[29] to NERC Staff explaining the clarification or explanation requested, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. NERC Staff shall review the request for Interpretation to determine whether it meets the criteria for a valid Interpretation. Based on this review, NERC Staff shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request. NERC Staff shall periodically communicate to the Standards Committee the status of all Interpretation requests that are pending resolution.

7.2.1: Rejection of an Interpretation Request

The Standards Committee may reject a request for Interpretation in the following circumstances:

- The request seeks approval of a particular compliance approach.[30]
- The issue can be addressed by incorporating the issue into an existing standard development project or a project contemplated in a published development plan.
- The request seeks clarification or explanation of any element of a Reliability Standard other than a Requirement or referenced attachment.
- The issue has already been addressed in the record.[31]
- The request identifies an issue and proposes the development of a new or modified Reliability Standard (such issues should be addressed via submission of a SAR).
- The request seeks to alter the scope of a Reliability Standard.
- The meaning of a Reliability Standard is clear and evident by inspection or the plain words that are written.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the rejection to the entity requesting the Interpretation within 10 business days of the decision to reject.

[29] The *Request for Interpretation* form is posted on the NERC Standards web page.

[30] Requests that seek approval of specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

[31] The "record" is generally understood to refer to the record of development, regulatory approval record, or other materials developed to support the development or approval of a Reliability Standard.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, it shall authorize NERC Staff to assemble an Interpretation drafting team for approval by the Standards Committee with the relevant expertise to address the request.

7.2.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a draft Interpretation, consistent with Section 7.1. Interpretations shall be developed in accordance with the following process:

- NERC Staff shall review the draft Interpretation to determine whether it meets the criteria for a valid Interpretation and shall provide to the Standards Committee a recommendation to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after reviewing the recommendation, shall determine whether to authorize posting of the draft Interpretation for comment and ballot.
- Interpretations shall be balloted in the same manner as Reliability Standards (*see* Section 4.0).

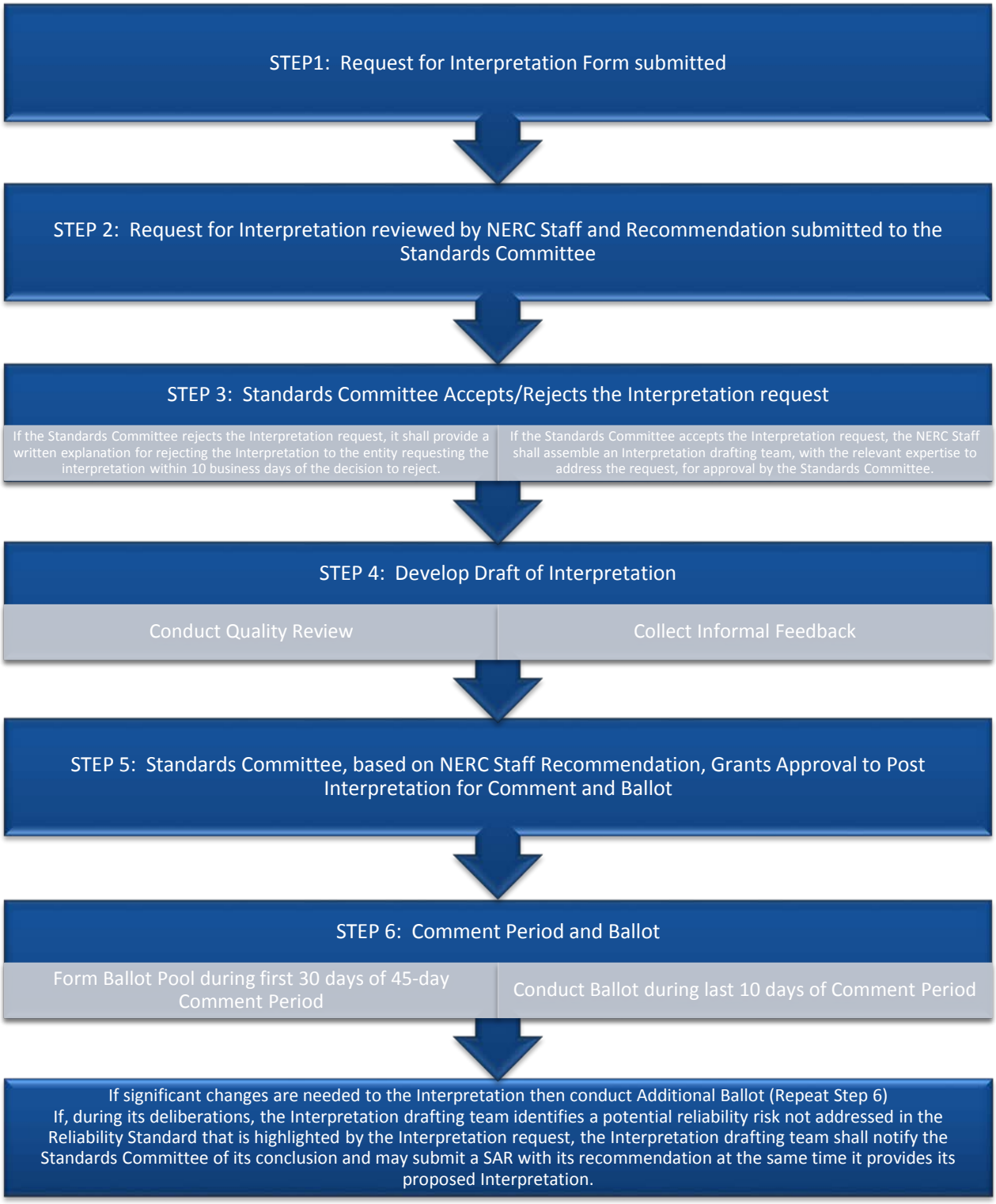
If the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic criteria for what constitutes a valid Interpretation (*see* Section 7.1), the Interpretation drafting team shall notify 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 in writing and the disposition of the Interpretation shall be posted.

If, during its deliberations, the Interpretation drafting team identifies a potential reliability risk not addressed 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 its recommendation at the same time it provides its proposed Interpretation.

If the ballot pool approves the Interpretation, NERC Staff shall review it to determine whether it meets the criteria for a valid Interpretation and shall make a recommendation to the NERC Board of Trustees regarding adoption.

If an Interpretation drafting team recommends modifying a Reliability Standard based on its work in developing the Interpretation, the Board of Trustees shall be notified of this recommendation at the time the Interpretation is submitted for adoption. Following Board of Trustees adoption, the Interpretation shall be filed with the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable Governmental Authorities.[33] The Interpretation shall stand until it can be incorporated into a future revision of the Reliability Standard or is retired due to a future modification of the applicable Requirement.

[33] NERC will maintain a record of all Interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Staff and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Staff shall assemble an Interpretation drafting team, with the relevant expertise to address the request, for approval by the Standards Committee.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Standards Committee, based on NERC Staff Recommendation, Grants Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a potential reliability risk not addressed 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 its recommendation at the same time it provides its proposed Interpretation.

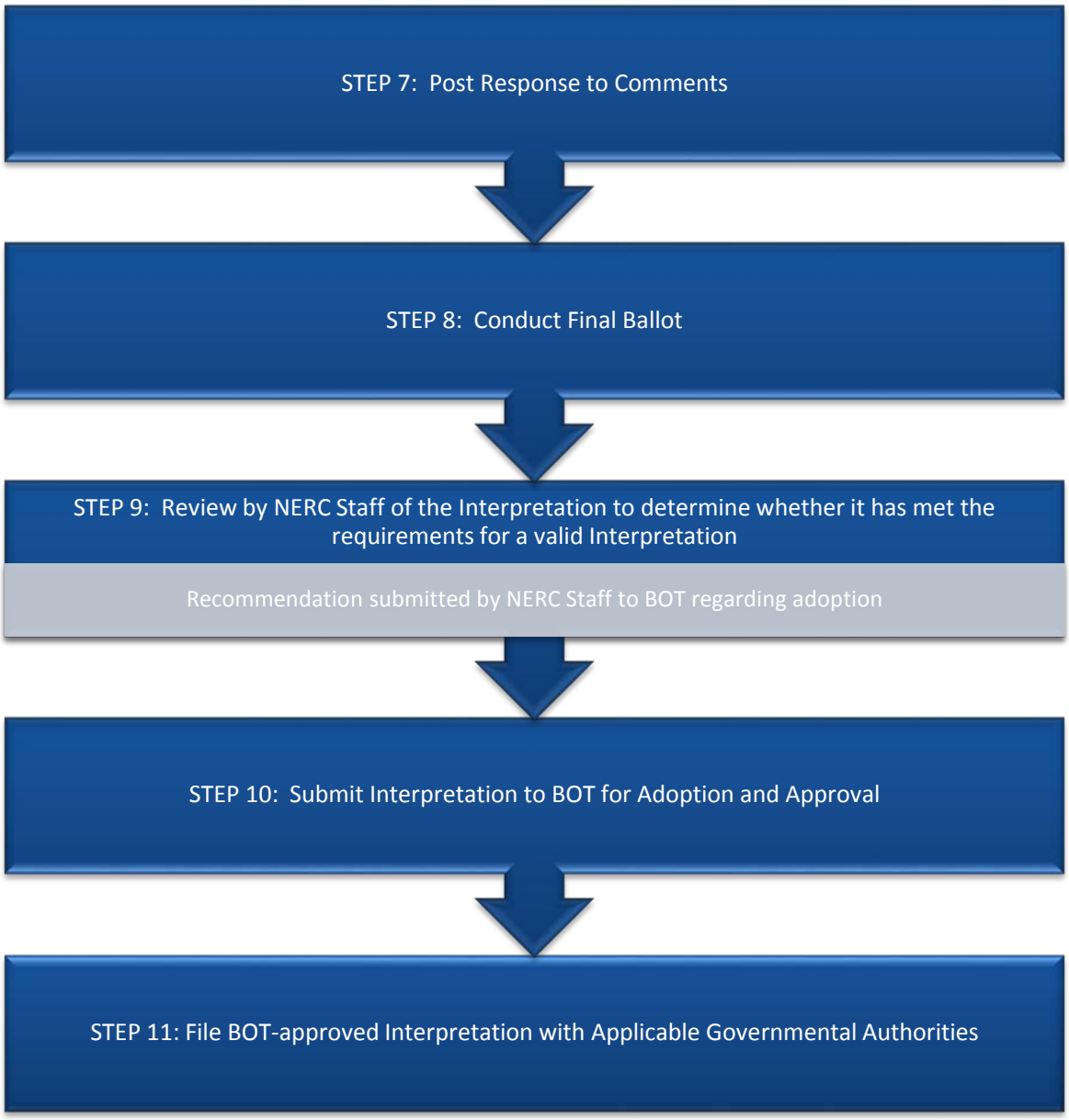


FIGURE 2: Process for Developing an Interpretation

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 or its designee 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.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

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 or its designee 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.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

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[34] 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.

Where a Regional Entity is not organized on an Interconnection-wide basis, but a Variance is proposed to apply to Registered Entities within an Interconnection wholly contained in that Regional Entity's footprint, the Variance may 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

[34] 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.

a Reliability Standard is approved. Each request for a 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.[35]

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 confidentiality 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

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

[35] 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.

their organizations that have signed confidentiality agreements with NERC.[36] 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.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

The following flowchart illustrates the process for developing a Reliability Standard responsive to an imminent, confidential issue:

[36] 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.

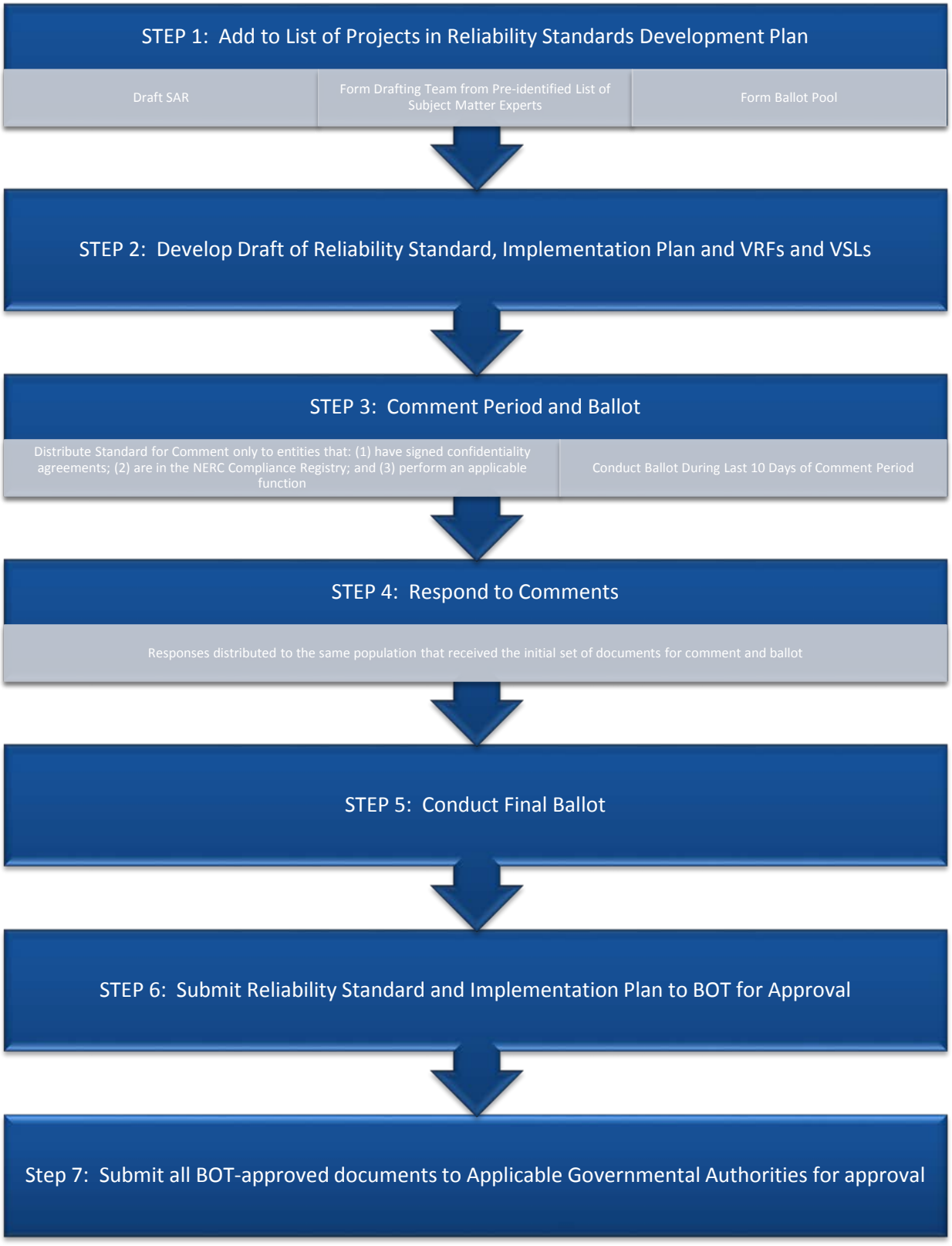


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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 confidentiality 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.[37] 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.

[37] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

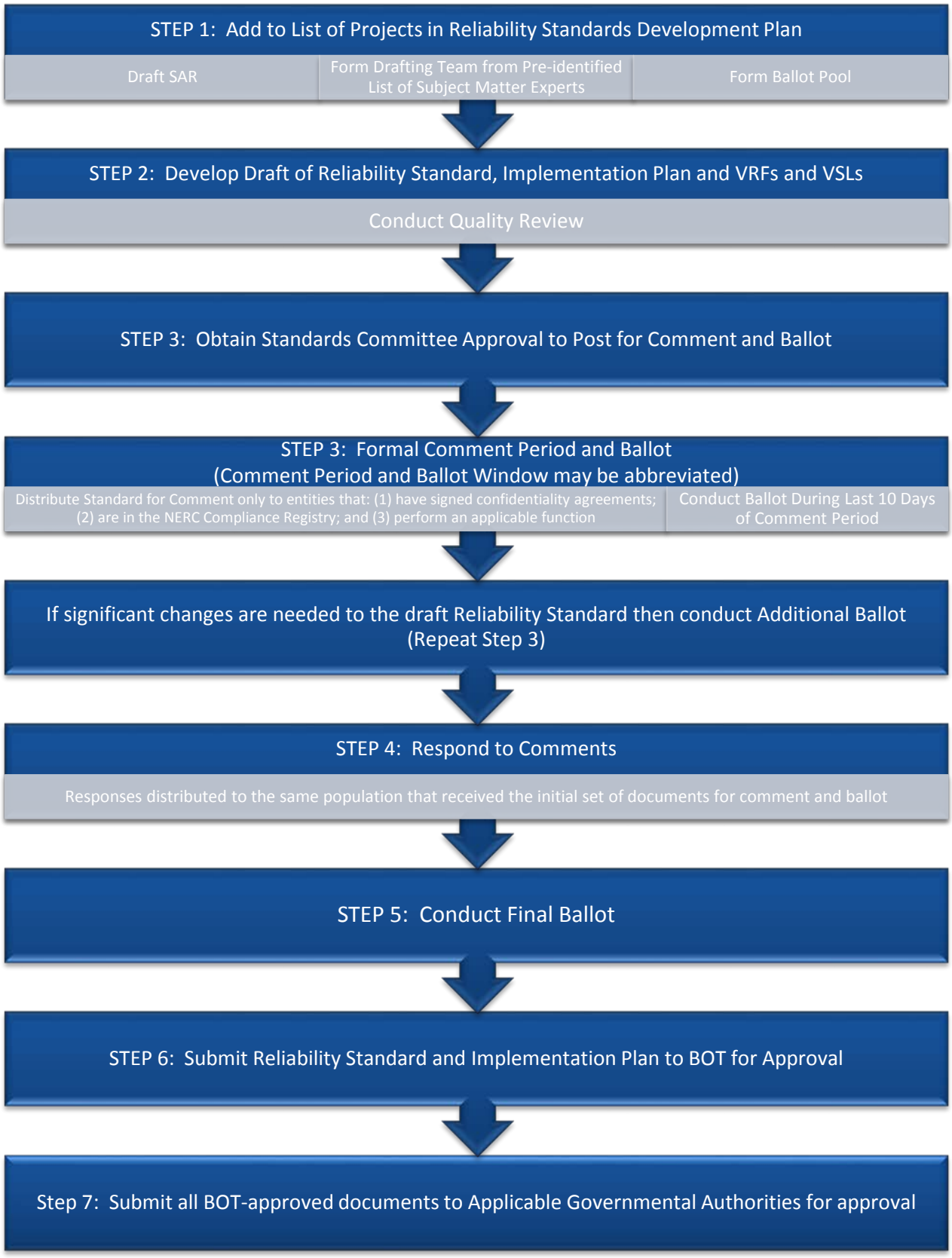


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Posting Supporting Technical Documents Alongside an Approved Reliability Standard

The NERC Standards Committee oversees the development and approval of technical documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. Supporting technical documents may explain or facilitate understanding of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any mandatory Requirements shall be incorporated into the Reliability Standard in the Reliability Standard development process.

This Section provides the process by which any stakeholder may propose a supporting technical document to an approved Reliability Standard. The process outlined in this section is designed so each supporting document receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting technical document to an approved Reliability Standard.

During the standard development process, standard drafting teams may develop and post supporting technical documents to the pertinent project page, in accordance with Section 4.0. Following approval of the Reliability Standard, those documents may be posted alongside the standard without requiring separate Standards Committee authorization under this Section.

The types of supporting technical documents that may be approved for posting alongside an approved Reliability Standard under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding of an approved Reliability Standard.
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document cannot establish new Requirements or modify Requirements in any existing Reliability Standard.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or a Reference document.

Documents that contain specific compliance approaches or examples are not considered supporting technical documents under this Section.

11.2: Process for Proposing and Evaluating Supporting Technical Documents

Proposals for supporting technical documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting technical document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting technical document meets the following criteria:

1. the document is a type of supporting technical document subject to this Section, as described in Section 11.1;

2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

If NERC Staff determines that the proposed supporting technical document meets all three criteria specified above, NERC Staff shall submit the proposed supporting technical document to the Standards Committee as specified in Section 11.3 below.

If NERC Staff determines that the proposed supporting technical document does not meet the first or second criterion specified above, NERC Staff shall notify the submitter, in writing, that the document will not be posted as a supporting technical document under this Section. This notification shall include an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of its determination at the next regularly-scheduled Standards Committee meeting.

If NERC Staff determines that the proposed supporting technical document meets the first and second criteria, but has not yet received adequate stakeholder review under the third criterion, NERC Staff shall make a recommendation to the Standards Committee to authorize posting the proposed supporting technical document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless the Standards Committee directs otherwise. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide them to the submitter for consideration. If the submitter modifies the proposed supporting technical document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient technical review.

11.3: Approving a Supporting Technical Document

After determining that the proposed supporting technical document meets the three criteria specified in Section 11.2, NERC Staff shall present the supporting technical document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting technical document with the approved Reliability Standard on the pertinent NERC website page(s).

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 periodic review of that Reliability Standard.

For a project that is focused solely on the periodic review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45-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 days.

The Standards Committee shall post the proposed revisions for a 45-day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

- Submit the revised process or processes for ballot pool approval;
- Repeat the posting for additional inputs after making changes based on comments received;
- Remand the proposal to the sponsor for further work; or
- 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, Interpretation, 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. 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.

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Summary of Proposed Revisions to the NERC Standard Processes Manual – Second Posting

Appendix 3A to the NERC Rules of Procedure

Revisions are proposed to sections of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure.

Redline documents showing the changes from the currently-approved (2013) SPM as well as changes from last posted version of the revised SPM are available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 45-day formal comment period from June 25, 2018 through August 9, 2018. An additional ballot will be conducted from July 30 – August 9, 2018. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background Information

Under the oversight of the NERC Standards Committee (SC), a small group consisting of Standards Committee Process Subcommittee (SCPS) members and NERC staff have reviewed specific sections of the NERC SPM for the purpose of proposing revisions to clarify and improve existing language and processes.

An initial draft of revisions to Section 6 (field tests) was posted for informal comment from September 29, 2015 through October 28, 2015. A draft revised SPM showing revisions to several sections was posted for formal comment from March 20, 2017 through May 3, 2017. The ballot results showed a quorum of 78.65% with an approval rating of 64.72%.

Revisions have been made to address the comments from the 2017 posting period. In addition, revisions are proposed in other sections to clarify language, improve readability, and update language to reflect updates in definitions and the recent dissolution of the NERC Board of Trustees Standards Oversight and Technology Committee. The document has also been reformatted into the current NERC document template.

Summary of Revisions

Section 1.0: Introduction

Revisions are proposed in Section 1.0: Introduction to clarify and streamline language. A provision is added to clarify that the term “days”, unless otherwise specified, refers to calendar days (corresponding changes are also made throughout the document).

Section 2.0: Elements of a Reliability Standard

As first proposed in 2017, updates are made to Section 2.1 - Definition of a Reliability Standard, to reflect the currently effective definition of this term in the NERC Rules of Procedure.

Revisions are proposed in Section 2.5: Elements of a Reliability Standard to clarify language and reflect the Standards Committee's guidance for the development of Technical Rationale documents.

Section 3.0: Reliability Standards Program Organization

Revisions are proposed in Section 3.0 – Reliability Standards Program Organization to clarify language. In section 3.4, information regarding the election of Standards Committee members is replaced with a reference to Appendix 3B to the Rules of Procedure, *Procedures for Election of Members of the Standards Committee*. Section 3.6 is modified to be consistent with revisions to Section 7.0 regarding the appointment of interpretation drafting teams. Revisions are also made to specify that the NERC Director of Standards may delegate authority to perform certain responsibilities under the SPM.

As first proposed in 2017, updates are made to Section 3.7 - Governmental Authorities, to allow for the inclusion of federal and provincial governments of non-U.S. North American jurisdictions that may approve Reliability Standards in the future.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

NERC proposes to reorganize language regarding posting periods and responding to comments to improve readability and organization (proposed Sections 4.12 – 4.14). In response to comments received on the changes proposed to Section 11.0, Section 4.4.2 is amended to state explicitly that drafting teams may develop and post technical documents to support draft Reliability Standards or related elements.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data (proposed new title: Process for Conducting Field Tests)

In response to comments, revisions were made to clarify roles, responsibilities, and process steps, including processes for approving field test requests. Other changes were made to improve the organization and readability of the section. For example, a new section was created, Section 6.1.2, to address compliance waivers specifically.

Section 7.0: Process for Developing an Interpretation

As first proposed in 2017, revisions are proposed to improve the organization of the section. Additional revisions are proposed to clarify language regarding what constitutes a valid Interpretation, including clarifying that requests for approval of specific compliance approaches are not proper Interpretation requests and should instead be pursued through the applicable NERC and Regional Entity guidance processes (Section 7.2.1). In response to comments, the SPM revisions team has determined to not pursue the previously-proposed changes for posting and balloting Interpretations.

Section 8.0: Process for Appealing an Action or Inaction

As first proposed in 2017, revisions are proposed to Sections 8.1 and 8.2 to specify that an appellant may withdraw its Level 1 or Level 2 appeal by providing written notice to the NERC Director of Standards.

Section 9.0: Process for Developing a Variance

Revisions are proposed to clarify that Variances that are proposed to apply to the Quebec Interconnection may be developed through the Northeast Power Coordinating Council Regional Reliability Standards development procedure.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

In response to comments, explanatory text is added between the header and flowchart appearing under Section 10.7.

Section 11.0: Process for Approving Supporting Documents (proposed new title: Process for Posting Supporting Technical Documents Alongside an Approved Reliability Standard)

Revisions are proposed to clarify that the scope of Section 11.0 is to define a process for approving the posting of supporting technical documents to approved Reliability Standards (i.e., Reliability Standards approved by applicable governmental authorities). In response to comments, revisions have been made to improve the clarity and readability of this section, particularly with respect to which documents and the circumstances under which this section applies.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

Revisions are proposed to clarify the terminology used to refer to periodic reviews.

Section 16.0: Waiver

Updates are made to reflect the dissolution of the Standards Oversight and Technology Committee.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~4

Effective ~~June 26, 2013~~TBD

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Section 1.0: Introduction 1
Section 2.0: Elements of a Reliability Standard 4
Section 3.0: Reliability Standards Program Organization 8
Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard 12
Section 5.0: Process for Developing a Defined Term 24
Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data 26
Section 7.0: Process for Developing an Interpretation 29
Section 8.0: Process for Appealing an Action or Inaction 33
Section 9.0: Process for Developing a Variance 35
Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue 37
Section 11.0: Process for Approving Posting Supporting Technical Documents Alongside an Approved Reliability Standard 42
Section 12.0: Process for Correcting Errata 45
Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards 46
Section 14.0: Public Access to Reliability Standards Information 47
Section 15.0: Process for Updating Standard Processes 48
Section 16.0: Waiver 49

Section 1.0: Introduction

1.1: Authority

This manual is published by the authority of the North American Electric Reliability Corporation ("NERC") Board of Trustees and has been incorporated into the NERC Rules of Procedure as Appendix 3A. It~~. 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~~ NERC 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. Unless otherwise specified, any period of time that is counted in days shall refer to calendar days.

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 teams, and the 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. The United States Federal Energy Regulatory Commission ("FERC") certified NERC ~~was certified~~ as the ERO effective July 2006. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes

NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***

  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***

  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***

  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***

  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***

  The process shall be transparent to the public.

- ***Consideration of views and objections***

  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***

  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***

  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

    - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
    - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***

  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***

  The International System of units is the preferred units of measurement in NERC Reliability Standards. 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, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System.~~,~~ ~~including without limiting the foregoing,~~ The term includes requirements for the operation of existing Bulk Power System ~~Facilities~~facilities, including cyber~~-~~security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ 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~~such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions).[1] ~~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.[2] 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.[3] 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.

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[1] *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

[2] 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.

[3] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

- **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, 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.[4]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies ~~which entities are assigned reliability requirements. T~~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.

[4] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provided on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[5]

- ***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~~ Reliability ~~standard~~Standard.[6] Each requirement in each ~~reliability~~ Reliability ~~standard~~ 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~~ Reliability ~~standard~~Standard, but are not part of the ~~reliability~~ Reliability ~~standard~~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.[7]
  - ***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.[8]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~***Application guidelines***: Guidelines to support the implementation of the associated Reliability Standard.~~

~~***Procedures***: Procedures to support implementation of the associated Reliability Standard.~~

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for

[5] 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.~~.~~

[6] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of a ~~reliability~~ Reliability S~~s~~tandard and is posted on the NERC ~~Web~~ web ~~Site~~site.

[7] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources ~~Web~~ web ~~Page~~page.

[8] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources ~~Web~~ web ~~Page~~page.

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~~ developed 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[9], 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.[10] The composition of the Standards Committee and the election of its members is set forth in Appendix 3B to the NERC Rules of Procedure, *Procedures for Election of Members of the Standards Committee*. ~~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.[11] 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.[12]

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 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

[9] 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.

[10] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

~~[11] 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.~~

[12] 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.

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,[13] 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, and Interpretations. ~~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.[14] 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.
- Develops and refines technical documents that aid in the understanding of Reliability Standards.

[13] The Director of Standards may delegate its authority to perform certain responsibilities specified in this manual to another member of the NERC Reliability Standards staff.

[14] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- 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 federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO ~~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~~ 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[15] 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.

[15] 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.[16]

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.

[16] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

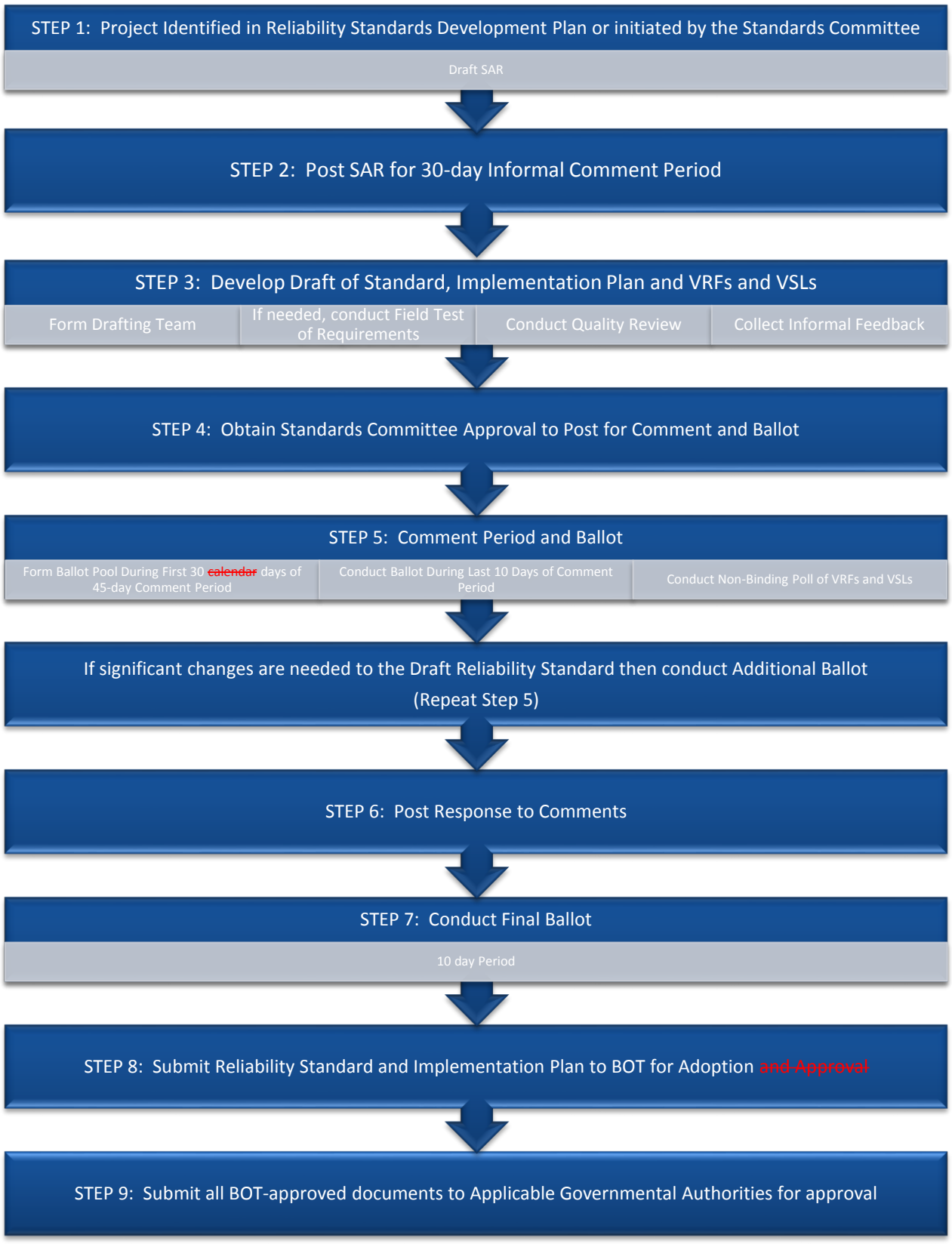


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR~~[17]~~ to the NERC Reliability Standards Staff.[18] 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,*[19] 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.

~~[17] The SAR form can be downloaded from the Reliability Standards Resources web page.~~

[18] The SAR form ~~can be downloaded from~~is available on the Reliability Standards Resources web page.

[19] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

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 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 during the public posting period. The drafting team may address the comments~~, 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 *Ten Benchmarks ~~for~~ of an Excellent Reliability Standard~~s~~*. 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 *Ten Benchmarks of an ~~for~~ Excellent Reliability Standard~~s~~*.

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~~ and that meet~~sing~~ the quality attributes identified in NERC's *Ten Benchmarks ~~for~~ of an Excellent Reliability Standard~~s~~*, with a goal of meeting ~~and~~ the 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.~~

The drafting team may, at its discretion, develop one or more supporting technical documents to help explain or facilitate understanding of the draft Reliability Standard, implementation plan, VSL, or VRF. These supporting technical documents may include, among other things: (1) reference documents designed to provide the drafting team's technical rationale, analysis, or explanatory information to support the understanding of the draft Reliability Standard or related element; or (2) white papers designed to explain a technical position or concept underlying the draft Reliability Standard or related element. Such documents may be posted during an informal comment period (Section 4.5) or formal comment period (Section 4.7).

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[20]

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,[21] 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 *Ten Benchmarks ~~for~~ of an Excellent Reliability Standard~~s~~* 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.

[20] 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.

[21] 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.

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.

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 or its designee 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~~ authorized deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[22]

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.[23]

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.

[22] 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.

[23] Closing dates may be extended as deemed appropriate by NERC Staff.

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.

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[24] 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[25] 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;

[24] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[25] 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.

- Negative;[26]
- Abstain.

4.12: Consideration of Comments and 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.

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. ~~However, a~~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. 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 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.

~~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~~13: 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

[26] 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.

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.

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.~~15~~14: 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~~15: 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~~ Board shall consider approval of the VRFs and VSLs associated with a ~~reliability~~ Reliability ~~standard~~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~~16: 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~~17: 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~~18: 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*[27] ("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.

[27] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests ~~and Collecting and Analyzing Data~~

While most drafting teams can develop ~~their~~ Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may ~~require~~ benefit from 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.

~~There are two types of field tests – tests of concepts and tests of requirements.~~ A field test is initiated by either a SAR or Reliability Standard drafting team. The drafting team is responsible for developing the field test plan, including the implementation schedule, and identifying compliance-related issues, such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis ~~for Validation of Concepts~~(collectively "field test")

- Field tests ~~or collection and analysis of data~~ to validate concepts ~~that support~~supporting the development of ~~Requirements~~ Reliability Standards should be conducted before finalizing the SAR for a project ~~is finalized~~. ~~If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.~~
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team shall work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The drafting team shall perform the field test, in coordination with NERC Staff and under the supervision of the assigned technical committee, in accordance with an approved field test plan. The drafting team may be assisted by other individuals based on the required expertise needed to support the field test.
- The lead NERC technical committee shall identify potential field test participants.

6.1.1: Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan;
- the implementation schedule; and
- a schedule for providing periodic updates regarding field test results and analysis to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team shall: (i) first receive approval from the lead NERC technical committee; and (ii) then receive approval from the Standards Committee.

The lead NERC technical committee shall base its approval on the technical adequacy of the field test request. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test request.

The Standards Committee's decision to approve the field test request shall be based on: (i) an affirmative recommendation from the lead NERC technical committee regarding the field test plan; and (ii) the Standard Committee's approval of the implementation schedule and the periodic update schedule. If the Standards Committee rejects the field test request, the Standards Committee shall provide an explanation of the decision to the lead NERC technical committee.

6.1.2: Compliance Waivers

~~If the conduct of a field test (concepts or Requirements) or data collection and analysis could~~Compliance waivers may be required for Registered Entities that would be rendered ~~Registered Entities~~ incapable of complying with the ~~current~~ Requirement(s) of a~~n~~ ~~approved~~currently-enforceable Reliability Standard ~~that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities~~ due to their participating~~tion~~ in the field test. ~~Upon request, the Standards Committee shall seek approval for the waiver from t~~The NERC Compliance Monitoring and Enforcement Program Staff ~~prior to the approval of the field test or data collection and analysis.~~ shall determine whether to approve any such compliance waivers and shall be responsible for approving any modifications or terminations to approved waivers that may become necessary in the course of conducting the field test. Staff shall notify the affected Registered Entities of all compliance waiver determinations.

6.1.3: Field Test Suspension for Reliability Concerns

During the field test, if NERC or the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System, NERC or the lead NERC technical committee shall:

- stop the activity;
- inform the Standards Committee that the activity was stopped; and
- if NERC or the lead technical committee is of the opinion a modification to the field test is necessary, provide a technical justification to the drafting team.

The Standards Committee, with the assistance of NERC Staff, shall:

- document the cessation or modification of the field test; and
- notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as continuing or terminating waivers, where applicable (see Section 6.1.2).

Prior to modifying the field test or restarting the field test after it has been stopped, the drafting team shall resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.4: Continuing, Modifying, or Terminating a Field Test

If the drafting team determines that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, it shall provide to the lead NERC technical committee and the chair of the Standards Committee a recommendation to continue, modify, or terminate the field test. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test and thereafter provide notice to the Standards Committee chair of its decision. The Standards Committee shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance-related issues such as continuing or terminating waivers (see Section 6.1.2).

If the duration of the field test is extended beyond the period of standard development, NERC Staff shall post the preliminary report and results on the NERC web site prior to the final ballot of the Reliability Standard.

~~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.[28] 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~~

Prior to initiating the field test, the Standards Committee chair and the lead NERC technical committee chair shall inform the Board of Trustees of the pending field test, the expected duration, and any requested compliance waivers.

During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either: (i) a preliminary report of the field test results of the field test to date, if the field test will continue beyond standard development; or (ii) a final report of the field test results. The Standards Committee chair shall keep the Board of Trustees informed regarding field test status.

~~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 approved field test plan and any modifications thereto, along with ~~or data collection and analysis plan, its approval, its participants, and~~ all field test reports and results, shall be publicly posted ~~for stakeholder review~~ on the ~~Reliability Standards~~NERC web ~~page~~site. The participant list shall also be posted, unless posting this list would present confidentiality or other concerns.

~~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.~~

~~[28] 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.~~

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.

7.1: Valid Interpretation Criteria

~~An~~ A valid Interpretation may only clarify or ~~interpret~~ explain the meaning of the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any referenced attachment ~~referenced in the Requirement being clarified~~. A valid Interpretation may not alter the scope or language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an Interpretation

The entity requesting ~~the~~ an Interpretation shall submit a *Request for Interpretation* form[29] to ~~the~~ NERC ~~Reliability Standards~~ Staff explaining the clarification or explanation ~~required~~requested, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. ~~The~~ NERC ~~Reliability Standards and Legal~~ Staff~~s~~ shall review the request for ~~interpretation~~ Interpretation to determine whether it meets the ~~requirements~~ criteria for a valid ~~interpretation~~Interpretation. Based on this review, ~~the~~ NERC ~~Standards and Legal~~ Staff~~s~~ shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request. NERC Staff shall periodically communicate to the Standards Committee the status of all Interpretation requests that are pending resolution.

7.2.1: Rejection of an Interpretation Request

~~For example,~~The Standards Committee may reject a request for ~~an~~ Interpretation ~~request may be rejected where it~~in the following circumstances:

- The ~~Requests~~ request seeks approval of a particular compliance approach.[30]~~;~~
- ~~Identifies a gap or perceived weakness in the approved Reliability Standard;~~
- The ~~Where an~~ issue can be addressed by incorporating the issue into an ~~active~~ existing standard ~~drafting team~~development project or a project contemplated in a published development plan.~~;~~
- The ~~Where it~~ request~~s~~ seeks clarification or explanation of any element of a Reliability Standard other than a Requirement or referenced attachment.~~;~~
- ~~Where a question~~The issue has already been addressed in the record.[31]~~;~~
- ~~Where the Interpretation~~The request identifies an issue and proposes the development of a new or modified Reliability Standard~~,~~ (such issues should be addressed via submission of a SAR).~~;~~
- ~~Where an Interpretation~~The request seeks to ~~expand~~ alter the scope of a Reliability Standard~~;~~. ~~or~~

[29] The *Request for Interpretation* form is posted on the NERC Standards web page.

[30] Requests that seek approval of specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

[31] The "record" is generally understood to refer to the record of development, regulatory approval record, or other materials developed to support the development or approval of a Reliability Standard.

- ~~Where t~~The meaning of a Reliability Standard is ~~plain on its face~~clear and evident by inspection or the plain words that are written.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the ~~rejecting~~ rejection ~~the Interpretation~~ to the entity requesting the Interpretation within 10 business days of the decision to reject.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, ~~the NERC Standards Staff~~it shall authorize NERC Staff to ~~(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 with the relevant expertise to address the request.

7.2.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a ~~"final~~ draft~~"~~ Interpretation, consistent with Section 7.1 ~~providing the requested clarity~~. Interpretations shall be developed in accordance with the following process:

- NERC Staff shall review the draft Interpretation to determine whether it meets the criteria for a valid Interpretation and shall provide to the Standards Committee a recommendation to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after reviewing the recommendation, shall determine whether to authorize posting of the draft Interpretation for comment and ballot.
- Interpretations ~~will~~ shall be balloted in the same manner as Reliability Standards (*see* Section 4.0).

If ~~stakeholder comments~~ the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic ~~expectations~~ criteria for what constitutes a valid Interpretation (*see* Section 7.1), ~~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 in writing and the disposition of the Interpretation shall be posted.

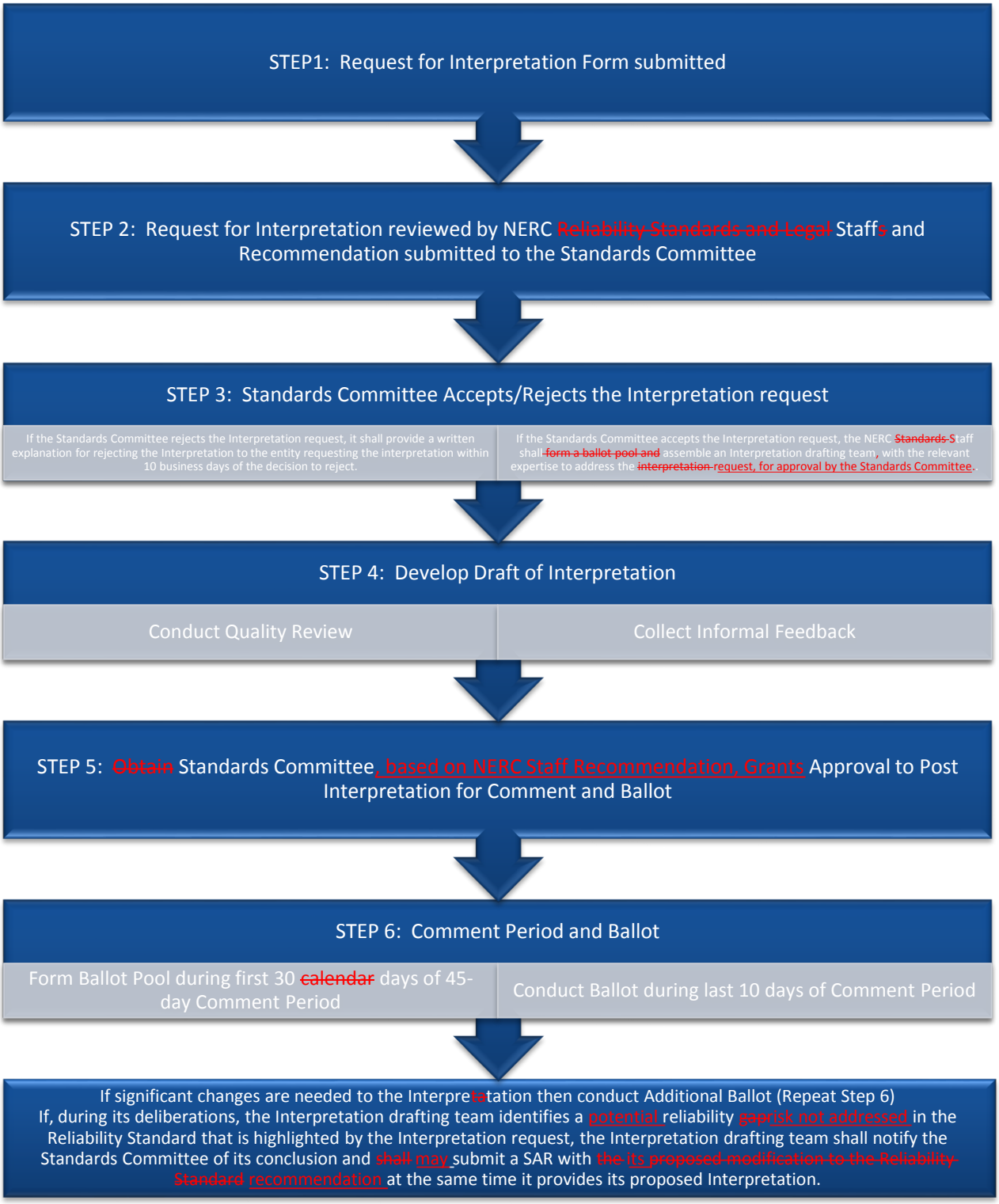
If, during its deliberations, the Interpretation drafting team identifies a potential reliability ~~gap~~ risk not addressed in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with ~~the proposed modification to the Reliability Standard~~its recommendation at the same time it provides its proposed Interpretation.

If the ballot pool approves the Interpretation, ~~The~~ NERC ~~Reliability Standards and Legal~~ Staff~~s~~ shall review ~~the final Interpretation~~it to determine whether it ~~has met~~meets the ~~requirements~~ criteria for a valid Interpretation~~.~~ and ~~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.[32]~~ If an Interpretation drafting team ~~proposes~~ recommends ~~a modification to~~modifying a Reliability Standard ~~as part of~~ based on its work in developing ~~an~~ the Interpretation, the Board of Trustees shall be notified of this ~~proposal~~ recommendation at the time the Interpretation is submitted for adoption. Following ~~by the~~ Board of Trustees adoption, ~~NERC Staff~~the Interpretation shall be filed with ~~the Interpretation for approval by~~ the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable

~~[32] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.~~

Governmental Authorities.[33] The Interpretation shall stand until ~~such time as the Interpretation~~it 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.



[33] NERC will maintain a record of all ~~i~~Interpretations associated with each standard on the Reliability Standards page of the NERC website.

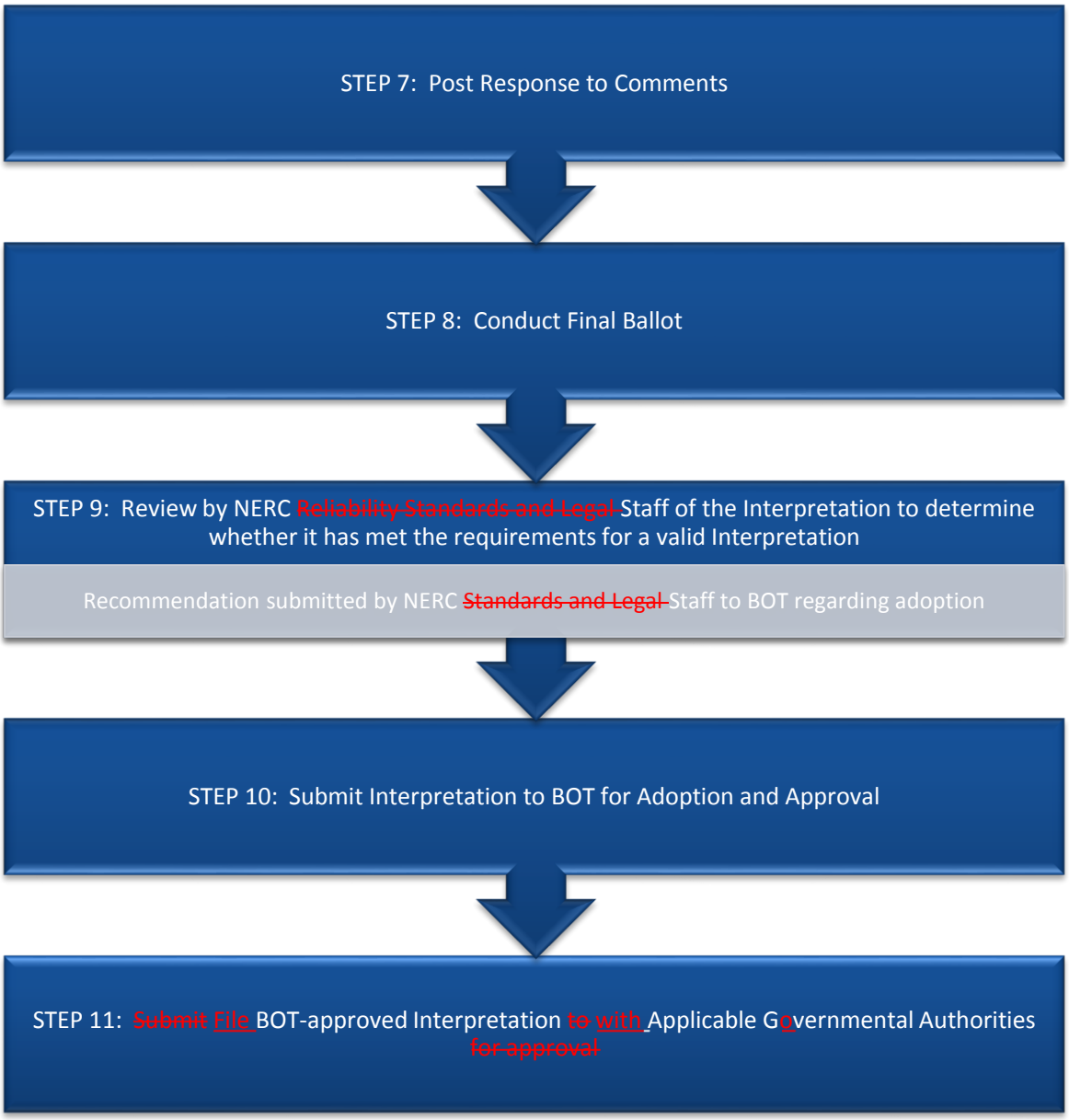


FIGURE 2: Process for Developing an Interpretation

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 or its designee 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.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

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 or its designee 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.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

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[34] 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.

Where a Regional Entity is not organized on an Interconnection-wide basis, but a Variance is proposed to apply to Registered Entities within an Interconnection wholly contained in that Regional Entity's footprint, the Variance may be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and

[34] 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.

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.[35]

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 confidentiality 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

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

[35] 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.

their organizations that have signed confidentiality agreements with NERC.[36] 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.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

The following flowchart illustrates the process for developing a Reliability Standard responsive to an imminent, confidential issue:

[36] 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.

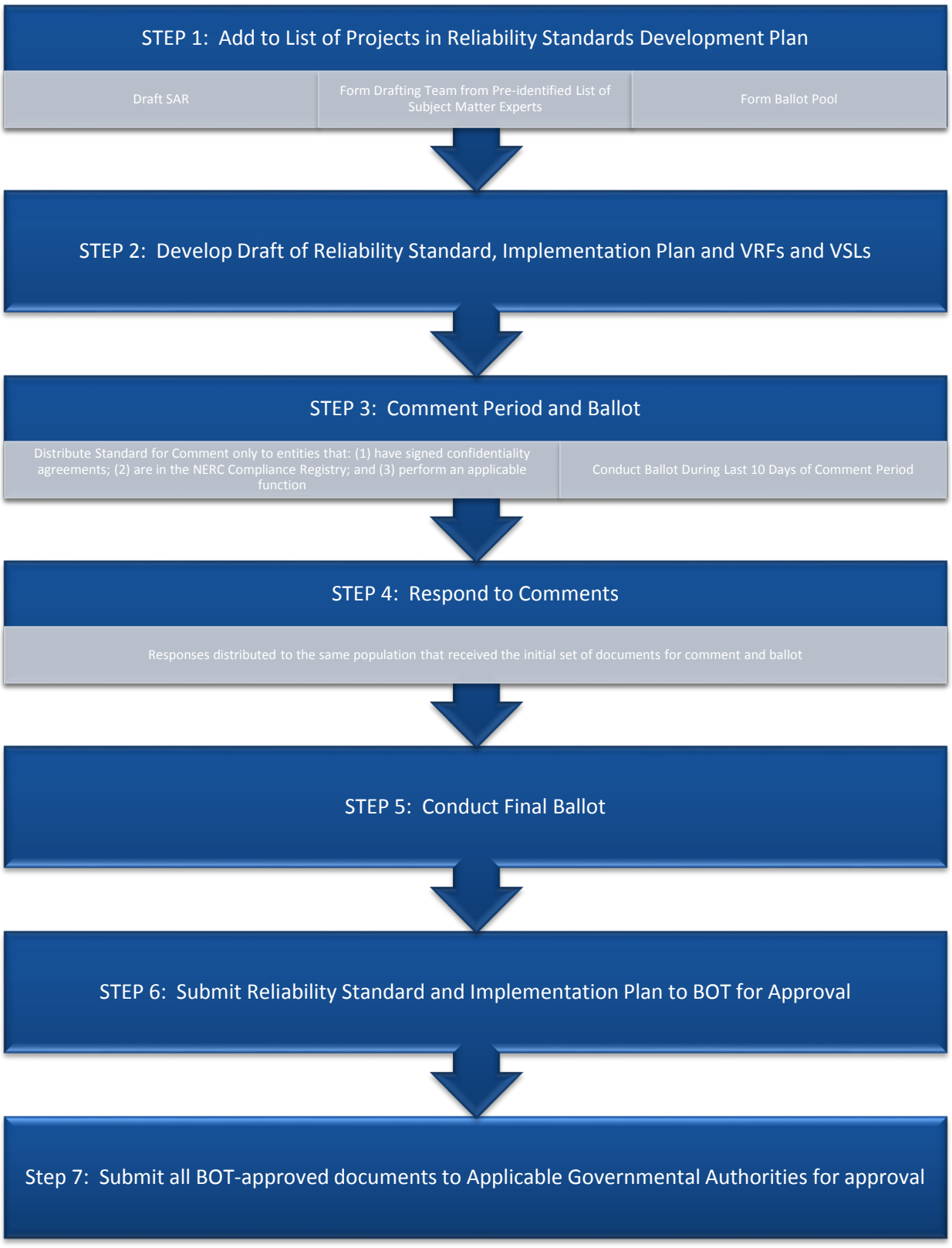


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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 confidentiality 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.[37] 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.

[37] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

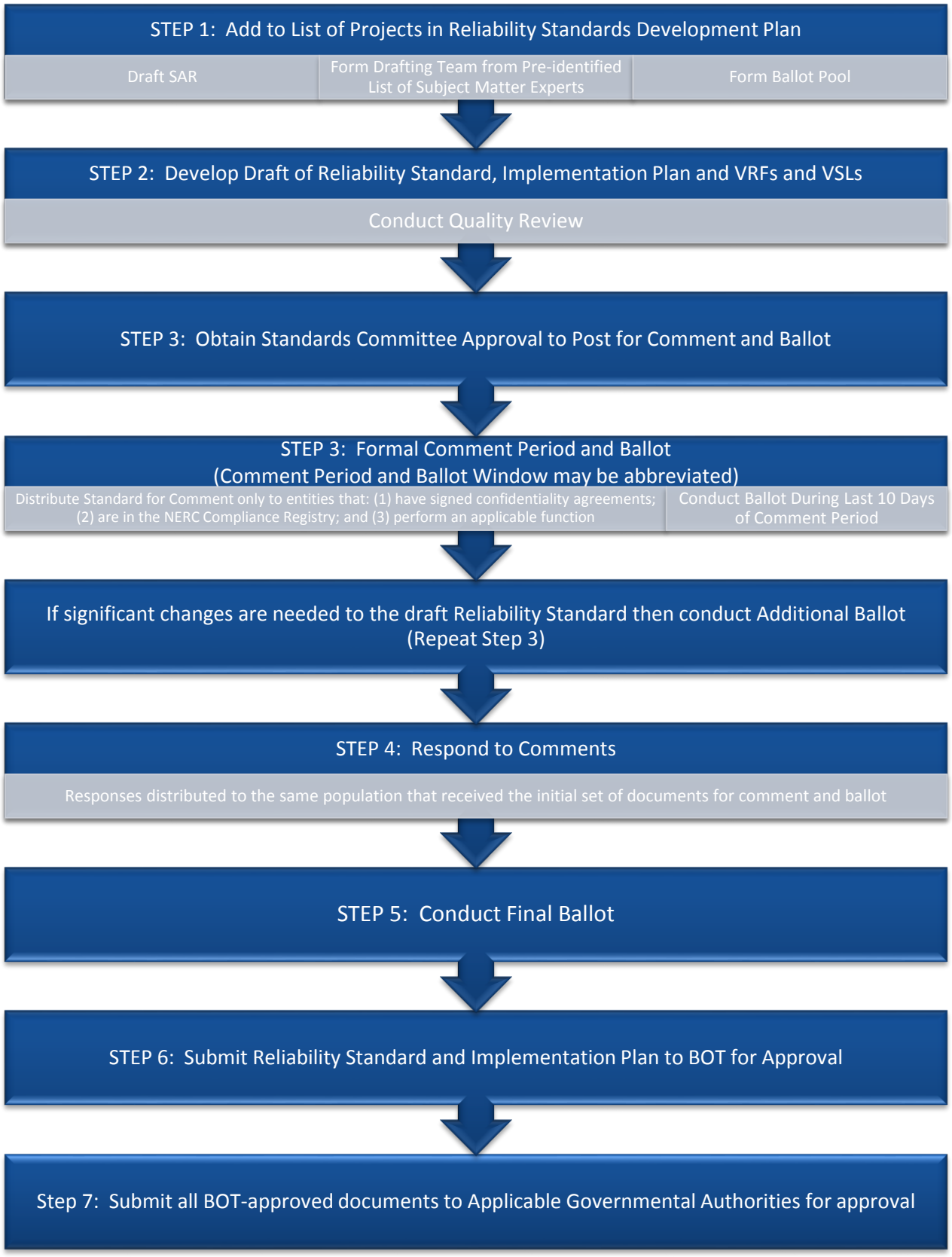


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for ~~Approving~~ Posting Supporting Technical Documents Alongside an Approved Reliability Standard

The NERC Standards Committee oversees the development and approval of technical documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. ~~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~~Supporting technical documents may explain or facilitate ~~implementation~~ understanding of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any mandatory 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.~~ This Section provides the process by which any stakeholder may propose a supporting technical document to an approved Reliability Standard. The process outlined in this section is designed so each supporting document receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting technical document to an approved Reliability Standard.

During the standard development process, standard drafting teams may develop and post supporting technical documents to the pertinent project page, in accordance with Section 4.0. Following approval of the Reliability Standard, those documents may be posted alongside ~~an approved Reliability Standard~~the standard without requiring separate Standards Committee authorization under this Section.

~~The Standards Committee shall authorize the posting of all supporting references[38] 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~~ The process outlined in this section is designed so each ~~that the~~supporting ~~document has had~~receives ~~stakeholder review to verify the accuracy of the technical content~~ prior to being posted as a supporting technical document to an approved Reliability Standard. ~~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.~~

11.1: Types of Supporting Technical Documents

The types of supporting technical documents that may be approved for posting alongside an approved Reliability Standard under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding ~~and interpretation~~ of an approved 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.~~

~~[38] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.~~

~~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.~~
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document cannot establish new Requirements or modify Requirements in any existing Reliability Standard.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or ~~one of the documents above~~a Reference document.

Documents that contain specific compliance approaches or examples are not considered supporting technical documents under this Section.

11.2: Process for Proposing and Evaluating Supporting Technical Documents

Proposals for supporting technical documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting technical document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting technical document meets the following criteria:

1. the document is a type of supporting technical document subject to this Section, as described in Section 11.1;
2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

If NERC Staff determines that the proposed supporting technical document meets all three criteria specified above, NERC Staff shall submit the proposed supporting technical document to the Standards Committee as specified in Section 11.3 below.

If NERC Staff determines that the proposed supporting technical document does not meet the first or second criterion specified above, NERC Staff shall notify the submitter, in writing, that the document will not be posted as a supporting technical document under this Section. This notification shall include an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of its determination at the next regularly-scheduled Standards Committee meeting.

If NERC Staff determines that the proposed supporting technical document meets the first and second criteria, but has not yet received adequate stakeholder review under the third criterion, NERC Staff shall make a recommendation to the Standards Committee to authorize posting the proposed supporting technical document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless the Standards Committee directs otherwise. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide them to the submitter for consideration. If the submitter modifies the proposed supporting technical document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient technical review.

11.3: Approving a Supporting Technical Document

After determining that the proposed supporting technical document meets the three criteria specified in Section 11.2, NERC Staff shall present the supporting technical document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting technical document with the approved Reliability Standard on the pertinent NERC website page(s).

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~~periodic review~~"~~ of that Reliability Standard.

For a project that is focused solely on the ~~five-year~~periodic 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:

- Submit the revised process or processes for ballot pool approval;
- Repeat the posting for additional inputs after making changes based on comments received;
- Remand the proposal to the sponsor for further work; or
- 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, Interpretation, 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.[39]~~ 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.

~~[39] 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.~~

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%			
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%			

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
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%			
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%			

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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%			
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%			

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
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%			
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%			

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
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		
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		

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
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%			
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		

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
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%			
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		

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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%			
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
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		

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
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
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		

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
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013 in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
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		

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
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
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: %			

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
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.]		[illegible] organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.

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
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%			
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%			

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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		
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	

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448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative	
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	

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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.	
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.	Last RSC Meeting
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14			
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14			
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative		
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative		
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative		
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative		
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative		
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative		
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3	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%	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			

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						Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	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%	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		
499	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	10/8/2014	10/17/2014	Quorum: 84.63%/84.15%/84.15%/83.90%/83.41%/83.66%/83.96%/84.49%/83.96%/83.96%/84.22 Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		

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510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08 % Approval: 92.91%/92.15%/95.62 %	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07 %/87.56%/87.80%87. 56%86.59% Approval: 83.84%/95.34%/86.00 %/95.35%91.17%/83. 88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60 % Approval: 92.69%/93.55%/93.67 %	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46 %/81.71%/81.71%/81. 22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		

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527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 90.43%/91.17%/91.10%/91.01%/91.10%/91.17%/91.17%/91.34%/90.97%/91.40%/90.10%/91.01%/91.07%/91.07%/91.07%/91.34%/91.43%/90.75%/91.34%/91.01%/91.40%/91.01%/91.01%/91.01%/91.01%/91.01% Approval: 91.46%/88.57%/86.68%/97.06%/97.10%/81.06%/80.73%/96.38%/97.03%/69.80%/95.38%/93.62%/96.83%/97.00%/98.55%/87.37%/89.99%/84.38%/88.06%/90.37%/97.75%/91.28%/87.71%/89.44%/87.15%/98.24%	Affirmative--7/24/15		
533	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Final Ballots	7/22/2015	7/31/2015	Quorum: 85.98%/90.67%% Approval: 88.23%/96.84%	Affirmative--7/7/15		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	8/20/2015	Quorum: 75.92% Approval: 69.26%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Quorum: 84.34% Approval: 69.76%	Affirmative--9/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Quorum: 87.16% Approval: 62.55%	Affirmative--9/11/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48%	Affirmative--7/24/15		

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						Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57% Approval: 87.36%	Affirmative--9/18/15		
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/25/2015	10/5/2015	Quorum: 83.70% Approval: 48.10%	N egative--10/2/15		
542	Project 2010-05.3	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/29/2015	10/8/2015	Quorum: 84.28% Approval: 74.61%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Quorum: 89.16% Approval: 80.94%	Affirmative--9/8/15		
544	Project 2010-05.3	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Final Ballot	10/6/2015	10/15/2015	Quorum: 89.60% Approval: 90.01%	Affirmative--9/18/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Final Ballot	10/15/2015	10/26/2015	Quorum: 90.00% Approval: 96.38%	Affirmative--9/16/15		
546	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/9/2015	Quorum: 84.59%/84.49% Approval: 47.38%/48.00%	Abstention--11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Initial Ballot	11/3/2015	11/12/2015	Quorum: 84.40% Approval: 98.17%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 88.18% Approval: 53.60%	Affirmative--11/13/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/10/2015	11/19/2015	Quorum: 83.18% Approval: 57.29%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 85.38% Approval: 82.56%	Negative--12/8/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Final Ballot	12/8/2015	12/17/2015	Quorum: 88.65% Approval: 98.26%	Affirmative--11/5/15		
551	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	12/30/2015	1/8/2016	Quorum: 83.39%/80.88% Approval: 60.39%/92.94%	Affirmative--12/3015		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Additional Ballot	12/31/2015	1/11/2016	Quorum: 84.13%/83.17%/84.44% Approval: 70.64%/75.54%/94.30%	BAL-005-1--Negative--1/10/16 BAL-006--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55%	Affirmative--3/10/16		

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						Approval: 78.87%			
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15% Approval: 80.36%/93.43%	Affirmative--3/10/16		
555	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	4/27/2016	5/6/2016	Quorum: 81.03% Approval: 82.64%	Affirmative--5/6/16		
556	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	5/17/2016	5/26/2016	Quorum: 88.96%/88.36% Approval: 82.52%/83.37%	Affirmative--4/20/16		
557	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Final Ballot	6/15/2016	6/24/2016	Quorum: 84.52% Approval: 83.25%	Affirmative--5/6/16		
558	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Initial Ballot	7/25/2016	8/3/2016	Quorum: 84.50%/85.51% Approval: 67.25%/64.59%	Affirmative--8/1/16		
559	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Initial Ballot	8/4/2016	8/15/2016	Quorum: 80.45%/81.14%/80.79% Approval: 52.90%/66.87%/84.13%	Negative--8/4/16		
560	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Initial Ballot	8/26/2016	9/6/2016	Quorum: 85.00%/84.37%/84.62% Approval: 41.54%/41.77%/30.63%	Negative--9/6/16		
561	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Initial Ballot	8/30/2016	9/8/2016	Quorum: 82.75% Approval: 80.32%	Affirmative--9/8/16		
562	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Initial Ballot	9/2/2016	9/12/2016	Quorum: 75.43% Approval: 91.68%	Affirmative--9/12/16		
563	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Additional Ballot	10/5/2016	10/14/2016	Quorum: 83.33%/81.79% Approval: 70.77%/68.85%	Affirmative--10/13/16		
564	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Final Ballot	10/13/2016	10/24/2016	Quorum: 81.25% Approval: 91.31%	Affirmative--9/12/16		
565	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Additional Ballot	11/23/2016	12/5/2016	Quorum: 76.40%/76.63% Approval: 85.56%/75.54%	Affirmative--12/1/16		
566	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3	Additional Ballot	11/30/2016	12/9/2016	Quorum: 80.71%/82.43% Approval: 76.93%/77.17%	Affirmative--11/30/16		
567	Project 2015-08	Project 2015-08 Emergency Operations EOP-008-2	Final Ballot	11/30/2016	12/9/2016	Quorum: 93.36% Approval: 93.17%	Affirmative--11/30/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Final Ballot	12/2/2016	12/12/2016	Quorum: 90.74%/90.40% Approval: 74.30%/72.52%	Affirmative--12/2/16		
569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		

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572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71% Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	12/11/2017	Quorum:77.10% Approval: 63.91%	Affirmative--12/4/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73% Approval: 88.25%	Affirmative--12/4/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69% Approval: 89.46%	Affirmative--12/4/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Quorum: 80.93%/81.27% Approval: 97.50%/98.91%	Affirmative--3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/3/2018	4/12/2018	Quorum: 84.82%/84.86% Approval: 96.64%/97.88%	Affirmative--3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	2/23/2018	4/23/2018	Quorum: 80% Approval: 26.44%	Affirmative--4/16/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	3/16/2018	4/30/2018	Quorum: 79.50% Approval: 93.31%	Affirmative--4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	3/16/2018	4/30/2018	Quorum:78.06% Approval: 83.71%	Affirmative--4/25/18		

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594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Definition and Implementation Plan	Initial Ballot	3/16/2018	4/30/2018	Quorum: 81.33%/81.54% Approval: 46.71%/37.98%	Negative--4/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	4/27/2018	5/8/2018	Quorum: 81.82% Approval: 80%	Abstain--5/7/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/18/2018	7/3/2018	Quorum: 75.16% Approval: 68.45%	Affirmative--6/29/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/5/2018	7/16/2018	Quorum: 84.42% Approval: 71.85%	Abstain--5/7/17		
598	SPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	8/9/2018	Quorum: 80.34% Approval: 81.95%	Affirmative--8/7/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Final Ballot	8/3/2018	8/13/2018	Quorum:81.55% Approval: 72..55%	Affirmative--4/25/18		

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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

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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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	

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
			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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

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	

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
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	

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

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	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		– Cyber Security Standards					
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request 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-	TOP-001-3 TOP-002-4	Formal	08/6/14	09/19/14	Yes 9/22/14

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		IRO Reliability Standards	TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1				
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X 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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Generation Resources					
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
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-	Phase 2 of Balancing Authority	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	14.2.2	Reliability-based Controls: Time Error Correction					
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

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 2016-02	Modifications to CIP Standards	SAR	Informal	3/23/16	4/21/16	Yes 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	Emergency	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2015-08	Operations					
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 2016-02	Modifications of CIP Standards	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes 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
329	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-013-1	Formal	1/19/17	3/6/17	Yes 3/6/17
330	Project 2016-04	Modifications to PRC-025-1	SAR	Informal	3/20/17	4/3/17	Yes 4/3/17
331	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	3/14/17	4/11/17	Yes 4/11/17
332	Project 2016-02	Modifications to CIP Standard	TOCC	Informal	3/14/17	4/11/17	Yes 4/11/17
333	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Processes Manual					
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Limits					
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17
357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18
371	Standards Grading	2018 Periodic Review Standing Review Team	Standard Grading	Informal	5/14/18	6/28/18	Yes 6/28/18
372	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	5/18/18	7/3/18	Yes 7/2/18
373	SER	Standard Efficiency Review	SAR	Informal	6/7/18	7/10/18	Yes 7/10/18
374	Project 2016-02	Modifications to CIP Standard	CIP-002-5.1a SAR	Informal	6/14/18	7/13/18	Yes 7/13/18
375	Project 2016-02	Modifications to CIP Standard	CIP-003-7 SAR Order 843	Informal	6/14/18	7/13/18	Yes 7/13/18
376	SPM	Standards Processes Manual	SPM	Formal	6/25/18	8/9/18	Yes 8/9/18

RSC Meeting #18-3, Agenda Item 6.3: Comment History

(As of 8/15/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Regional Standards Committee approved Regional Standard Authorization Request (RSAR) for posting	June 23, 2015

Anticipated Actions	Date
1st 45-day Formal Comment Period	September 1, 2017 - October 18, 2017
2nd 45-day Formal Comment Period	April 16, 2018 – June 1, 2018
30-day Pre-ballot Period	
10-day ballot Period	
Board adoption	

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

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-NPCC-2

3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Planning Coordinator

   4.1.3. Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators

   4.1.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program, pertaining to islands wholly within the NPCC Region, having performance characteristics that prevents the frequency from remaining below 59.5 Hz for more than 30 seconds in accordance with Figure 1 *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

R3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per the NERC continent wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or
- The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3.

M3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program identified in Requirement R3. (Attachment C, Tables 1-3).

R4. Each Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- Within 30 calendar days, notify its Planning Coordinator that it does not meet the UFLS program parameters; and
- Within the following 180 calendar days from notification of the Planning Coordinator,

(1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or

(2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or (3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

M4. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R4.

Rationale for Requirement R5: An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria.

R5. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as, but not limited to, voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M5. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R5.

R6. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Each Planning Coordinator shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R6.

R7. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6 shall develop and submit an implementation plan with respect to inhibit thresholds for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R7.

R8. Each Distribution Provider and Transmission Owner shall implement the inhibit thresholds provided by the Planning Coordinator in accordance with Requirement R6 and based on the Planning Coordinator approved implementation plan in accordance with R7. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M8. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R8.

Rationale for Requirement R9: Ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. To that end, Requirement R11 requires entities to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R9. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its

Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M9. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R9.

R10. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M10. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R10.

R11. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M11. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R11.

R12. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

12.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2.

12.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection setting threshold curve in Figure 2.

M12. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R12.

R13. For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

13.1 Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

13.2 Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

13.3 Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

13.4 Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

M13. Each Generator Owner with existing non-nuclear units in service prior to July 1, 2015 which have underfrequency tripping that is not compliant with Requirement R10 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R13.

R14. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R13.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M14. Each Planning Coordinator in Ontario, Quebec and Maritime provinces shall provide evidence such as reports, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R14.

R15. Each Generator Owner, Distribution Provider or Transmission Owner within the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R13.4 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M15. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the NYISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R15.

R16. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 based on their licensing design shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

16.1 Set the underfrequency protection to operate at as a low frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.

16.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

16.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M16. Each Generator Owner of nuclear units that have generator trip settings above the generator trip curve in Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R16.

Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz
Design Performance Requirements

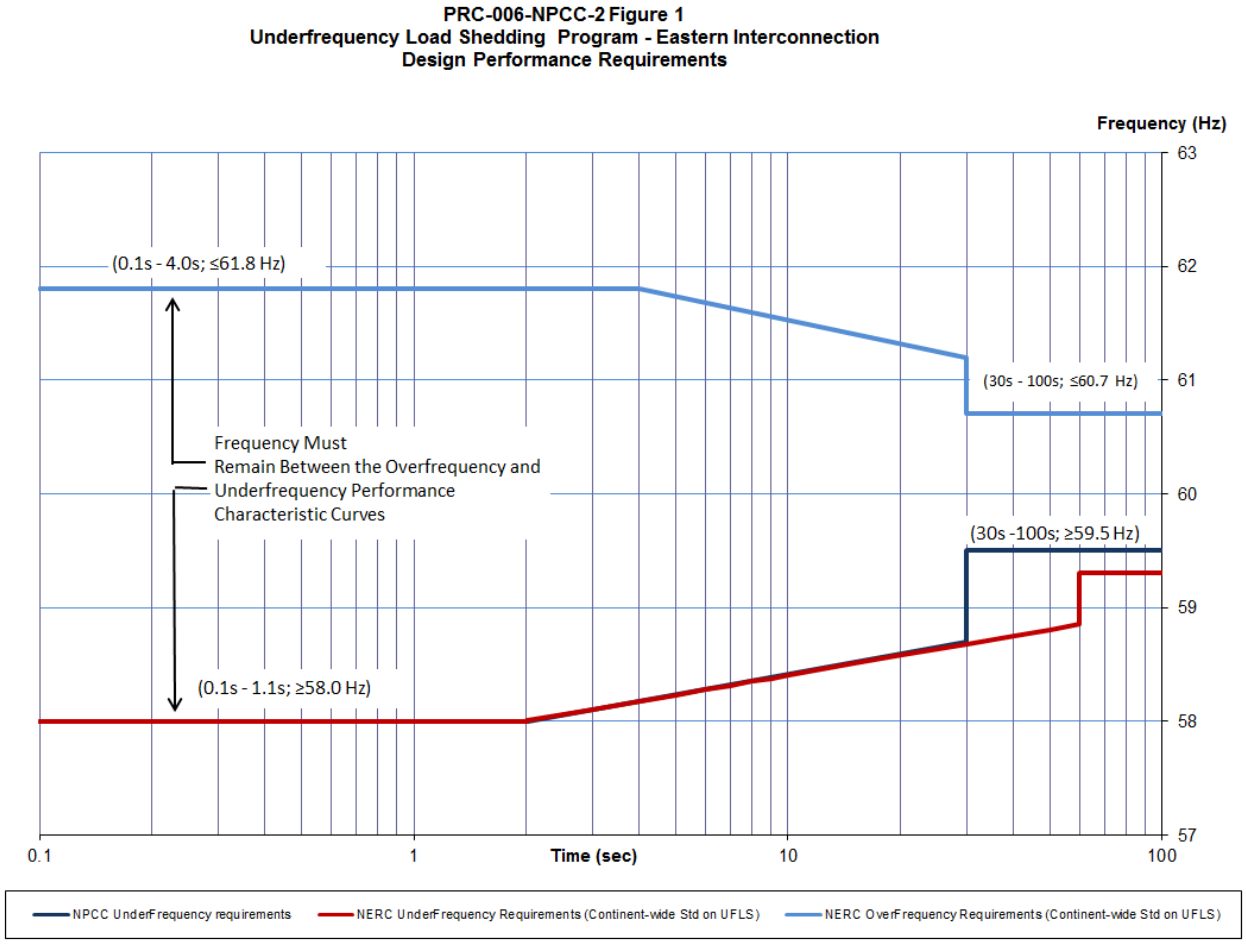
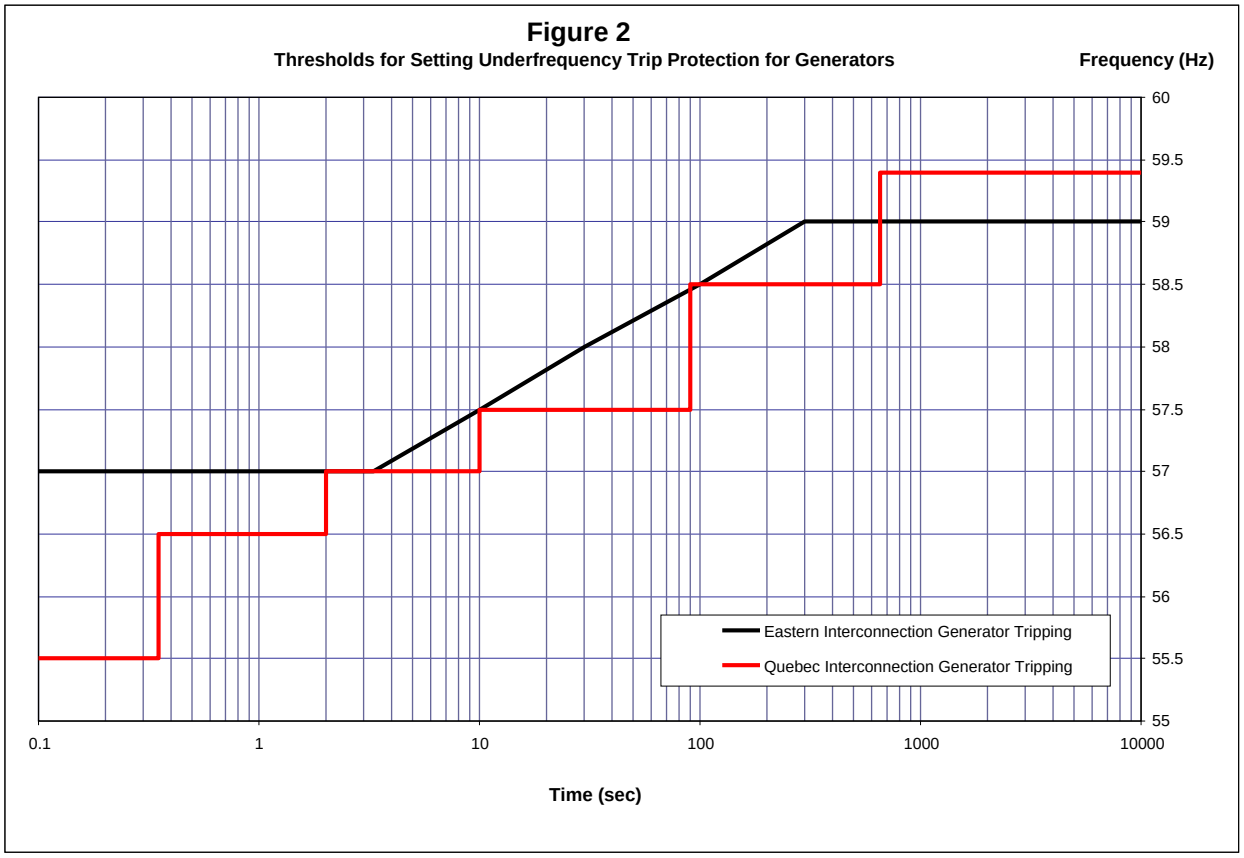


Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Northeast Power Coordinating Council

1.2. Evidence Retention:

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 2, 3, 4, 5, 8, and 9.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, 6, and 7.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 15.

The Generator Owner shall keep evidence for three calendar years for Measures 10, 11, 12, 13, and 16.

1.3. Compliance Monitoring and Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator failed to design an UFLS program having performance characteristics that prevent frequency from remaining below 59.5 Hz in accordance with Figure 1.
R2.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS but did so more than 40 calendar days but less than and including 50 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS but did so more than 50 calendar days but less than and including 60 days following a request.	The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS. within 60 calendar days following a request.
R3.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20% or less of the relays identified as included in the UFLS program, or amount of load tripped is within 10% deviation from the required amount of Load required to be shed at each stage	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20%-40% of the relays identified as included in the UFLS program, or amount of load tripped is within 20% deviation from the required amount of Load required to be shed at each stage m	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 40%-60% of the relays identified as included in the UFLS program, or amount of load tripped is within 30% deviation from the required amount of Load required to be shed at each stage.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on > 60% of the relays identified as included in the UFLS program, or amount of load tripped has a > 30% deviation from the required amount of Load required to be shed at each stage
R4.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations but exceeded the permissible	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program failed to meet all of items in Requirement 5 within 60

	Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items by a period of up to 10 calendar days but less than or equal to 20 calendar days.	Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items within a time greater than 20 calendar days but less than or equal to 30 calendar days.	time frame for one or more of the 4 items within a time greater than 30 calendar days but less than or equal to 60 calendar days.	calendar days of permissible time for each item.
R5.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 100% but more than (and including) 95% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 95% but more than (and including) 90% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more than (and including) 85% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 85% of relays within its region's UFLS program.
R6.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 calendar days and up to and including 40 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 calendar days but less than and including 50 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 calendar days but less than and including 60 calendar days of any changes.	The Planning Coordinator failed to provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 60 calendar days after any changes
R7.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 calendar days and up to and including 100 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request.
R8.	Implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with

	less than 100% but more than (and including) 95% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.
R9.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 15 calendar months but less than (and including) 16 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 16 calendar months but less than (and including)17 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 17 calendar months but less than (and including)18 calendar months since last update.	The Distribution Provider or Transmission Owner failed to provide to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 within 18 calendar months since last update.
R10.	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted.
R11.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 45calendar days and less than (and including) 55 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar days and less than (and including) 65 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar days and less than (and including) 75 calendar days of the Planning Coordinator's request.	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.
R12.	N/A	N/A	The Generator Owner with a new generating unit, or an existing	The Generator Owner with a new generating unit, or an existing generator increasing its net

			generator increasing its net capability by greater than 10%: Did not fulfill the obligation of Requirement R12; Part 12.1 OR Did not fulfill the obligation of Requirement R12, Part 12.2.	capability by greater than 10%, did not fulfill the obligations of Requirement R12, Part 12.1 and Part 12.2.
R13.	N/A	The Generator Owner failed to transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinatoras specified in Requirement R13, Part 13.2.	The Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified in Requirement 13, Part 13.1	The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner within the ISO-NE and in NYISO Planning Coordinator areas failed to arrange for compensatory load shedding as specified in Requirement R13, Part 13.3.
R14.	N/A	N/A	N/A	The Planning Coordinator did not apply the criteria described in Attachment A to determine the compensatory load shedding that is required.
R15.	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the criteria described in Attachment B to determine the compensatory load shedding that is required.
R16.	N/A	The Generator Owner failed to transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R16; Part 16.1 OR	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

		Coordinator as specified in Requirement R16, Part 16.3.	Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.	

D. Regional Variances

None.

E. Associated Documents

Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	2-9-2012	Adopted by Board of Trustees	
2	6-23-2015	RSAR Submitted	

Standard Attachments

PRC-006-NPCC-2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all UFLS islands in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units in their Planning Coordinator area that were in service prior to the effective date of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator within which the generator may operate to provide compensatory load shedding.

    2.2 In Ontario and in the Maritime provinces, the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in

addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units that were in service prior to the effective date of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, which have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 2, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment C

UFLS Table 1: Eastern Interconnection Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection Distribution Providers and Transmission Owners with 50 MW[2] or more and less than 100 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	14 – 25	14 – 25
2	59.1	0.10	0.30	14 – 25	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

UFLS Table 3: Eastern Interconnection Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	28 – 50	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Rationale Box:

Standard PRC-006-3, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.
PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.
Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria
- Generator dynamic modeling
- Dynamic VAR device modeling
- HVDC dynamic modeling

NPCC, Inc.

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Clean for RSC Review
December 7, 2017

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

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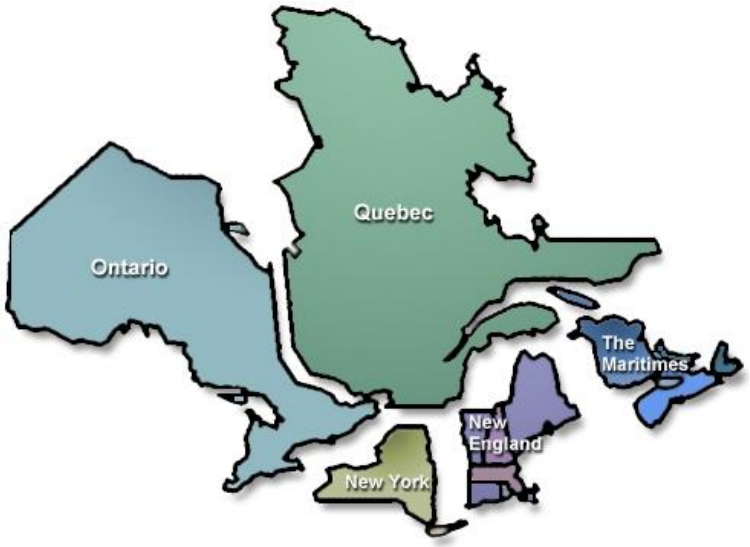
Process for the Review and Approval of Criteria, Guidelines and Procedures



Approved by the Reliability Standards Committee

Month xx, 2017

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2017	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL

Table of Contents

I. EXECUTIVE SUMMARY 3

II. BACKGROUND 3

III. APPLICABILITY OF NPCC CRITERIA 5

IV. TASK FORCE ROLES AND RESPONSIBILITIES 5

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 6

1. NEW DIRECTORY 6

2. DIRECTORY REVISIONS 8

a. Revisions to the Criteria Section of a Directory 8

b. Revisions to the Appendix Section of a Directory 10

c. Revisions To The NPCC Glossary Of Terms 12

d. Withdrawal Of Revision Requests 15

3. DIRECTORY RETIREMENT 15

4. MAINTENANCE OF LINKS AND ERRATA 15

VI. DIRECTORY CLARIFICATION PROCESS 16

a. Request for Criteria Clarification 16

B. APPEALS 19

VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL 19

VIII. DIRECTORY FORMAT AND VERSION CONTROL 19

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 20

APPENDIX A - DIRECTORY FORMAT TEMPLATE 25

APPENDIX B – NPCC REQUEST FOR CLARIFICATION 0

I. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and

translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC regional criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices. A link to the Directory Flowchart and the Directory Mapping documents is provided in the References section of this manual.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the References section of this manual.

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP. After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

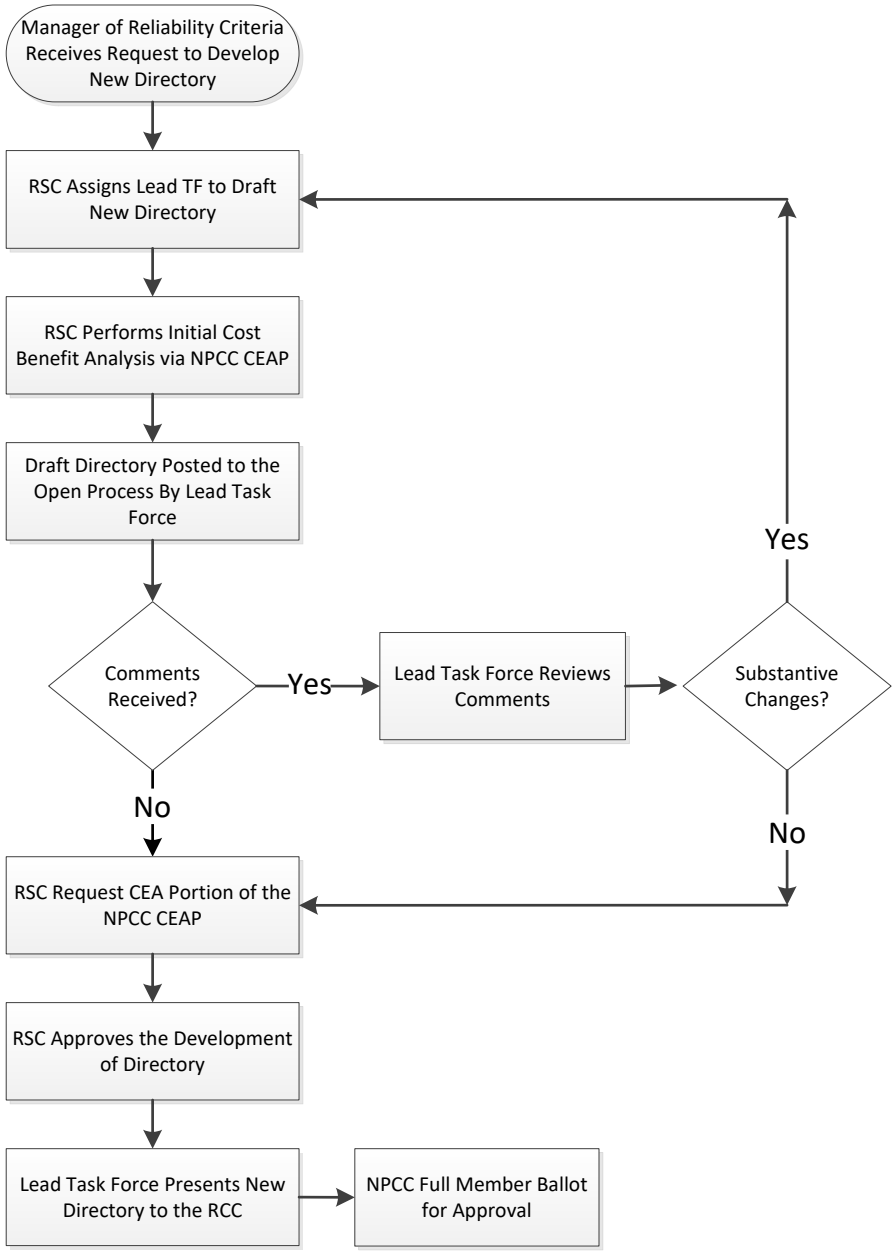
The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory. After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

---

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for establishing a new Directory is represented below in Figure 1:

Figure 1: New Directory



2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

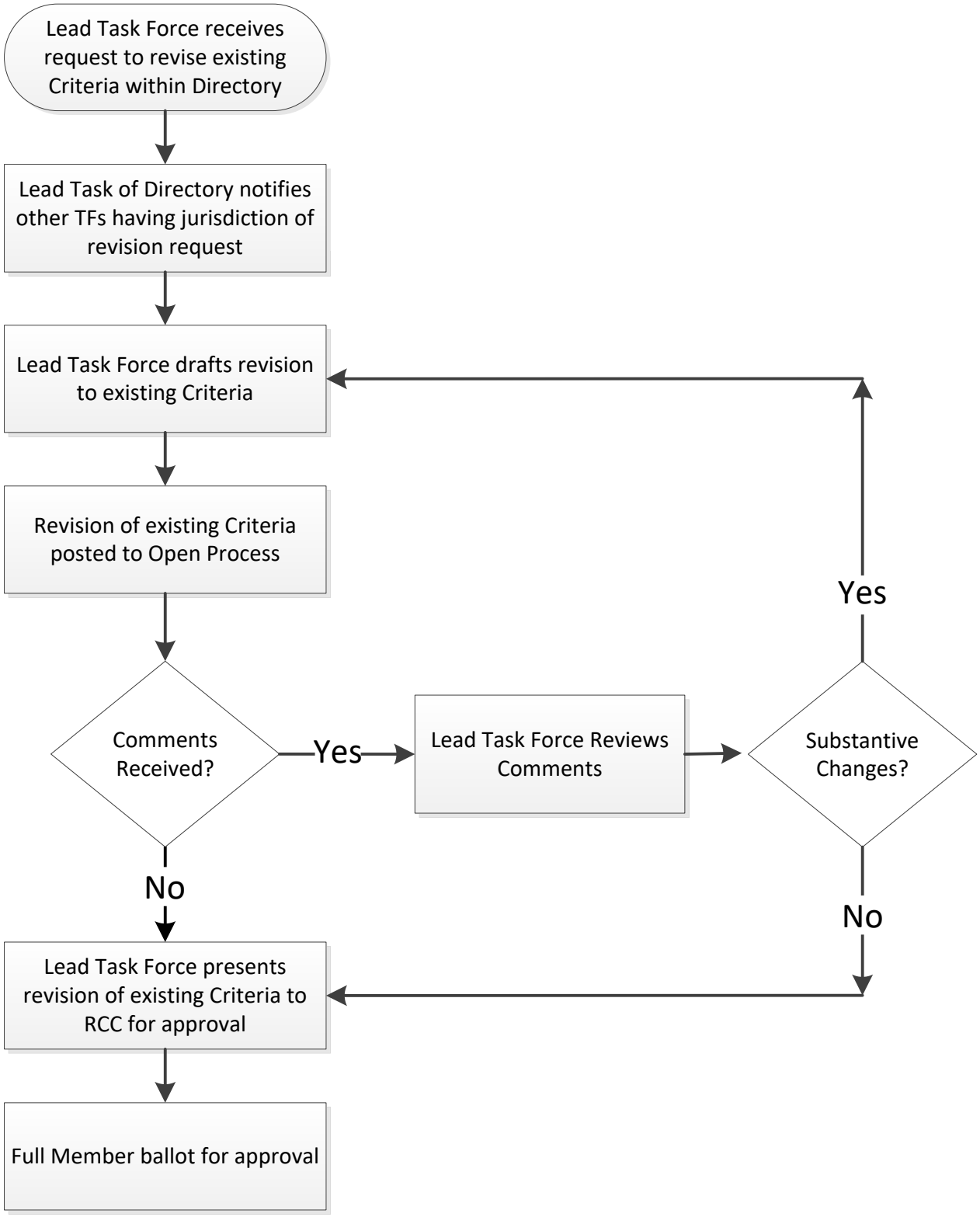
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised or retired. Revisions or retirements of Appendices shall only require Task Force approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

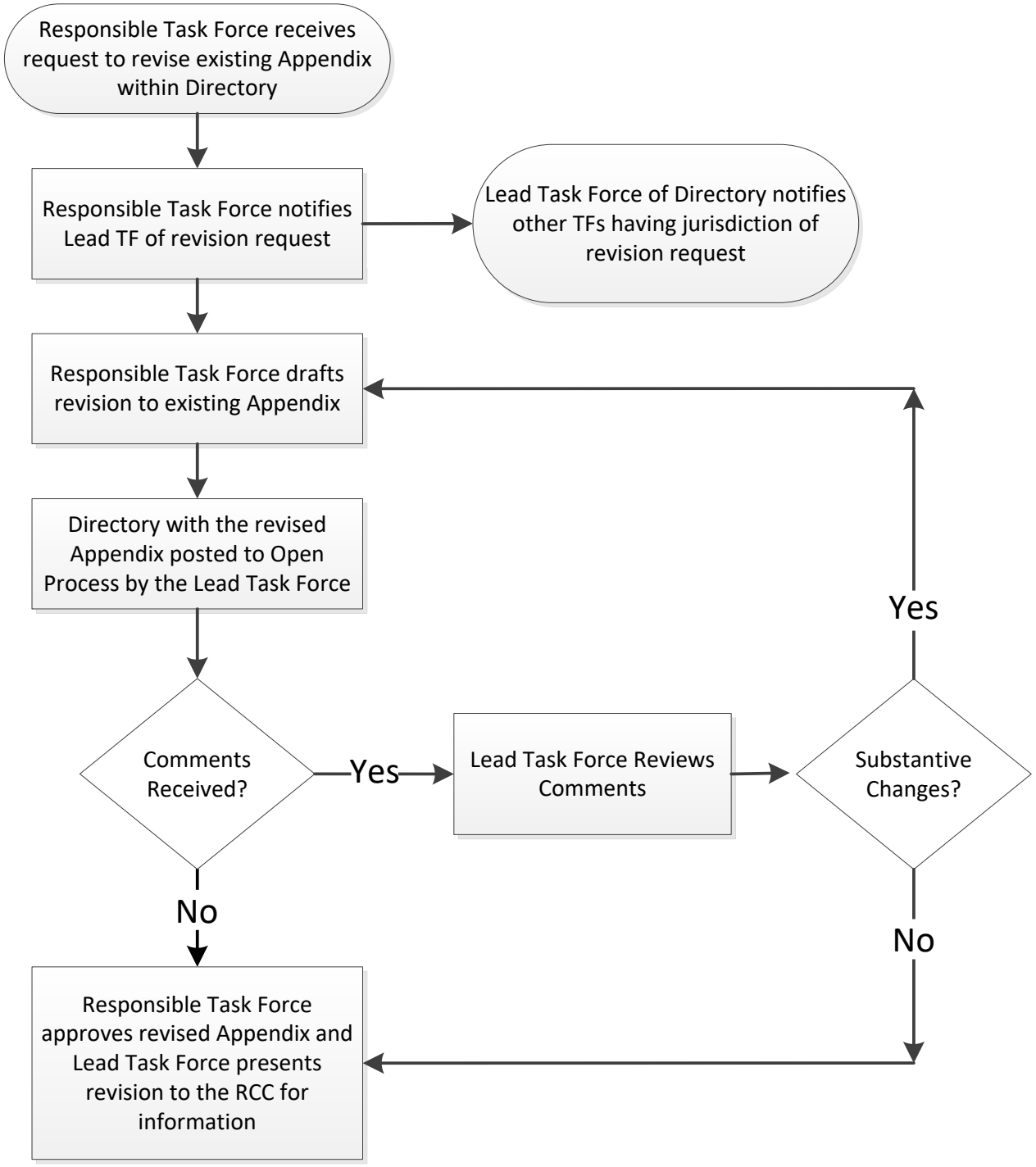
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix. If the responses to the comments received on the revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices



c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

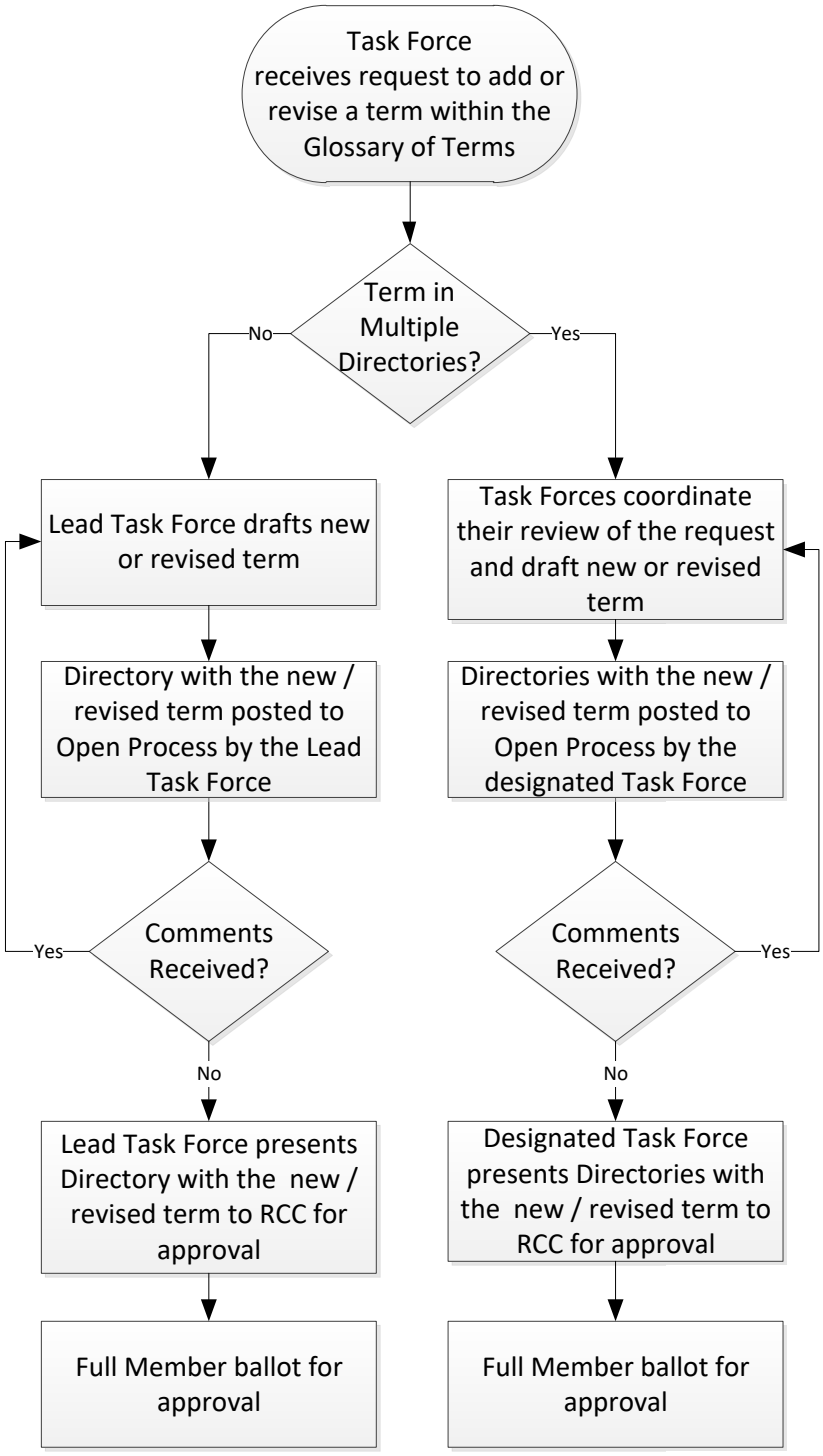
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. DIRECTORY RETIREMENT

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

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. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. MAINTENANCE OF LINKS AND ERRATA

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory

[2] The Request for Clarification Form is included in Appendix B of this document.

clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

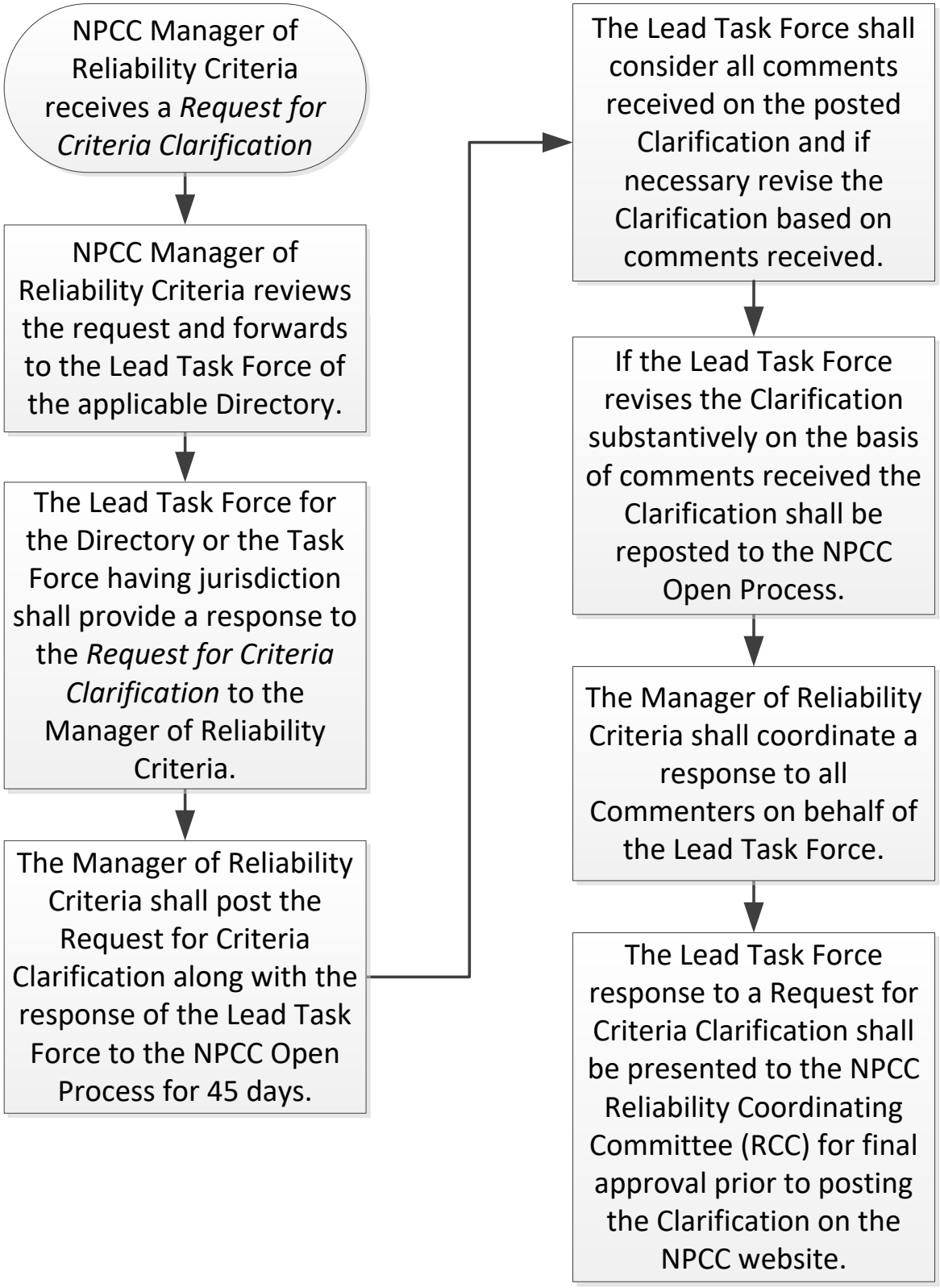
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL

The NPCC Directory Development and Revision Manual will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

VIII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes. See Appendix C for further details on the entire NPCC Open Process.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

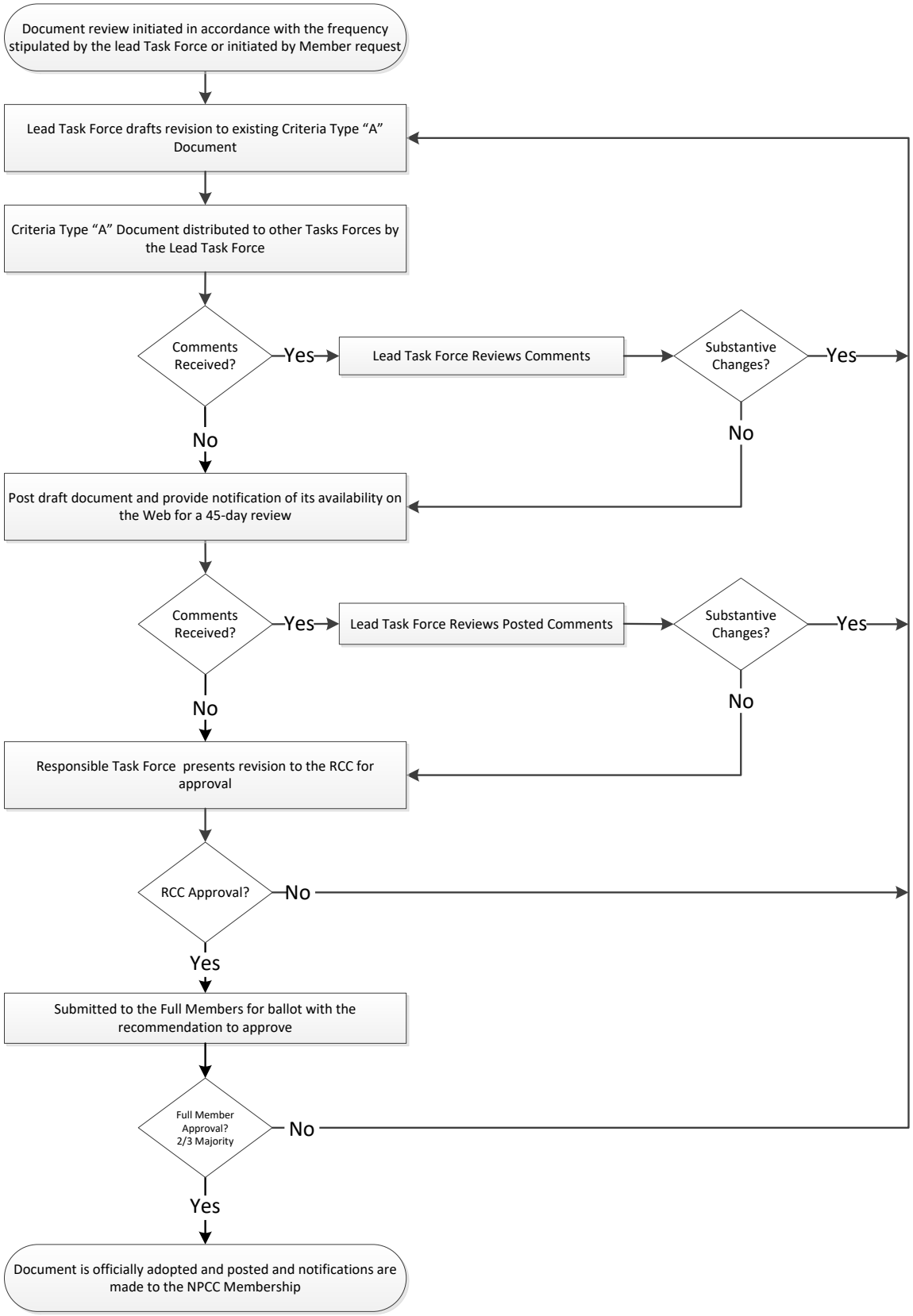
"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list
Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for non-compliance issues.

Retiring a Type "A" document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

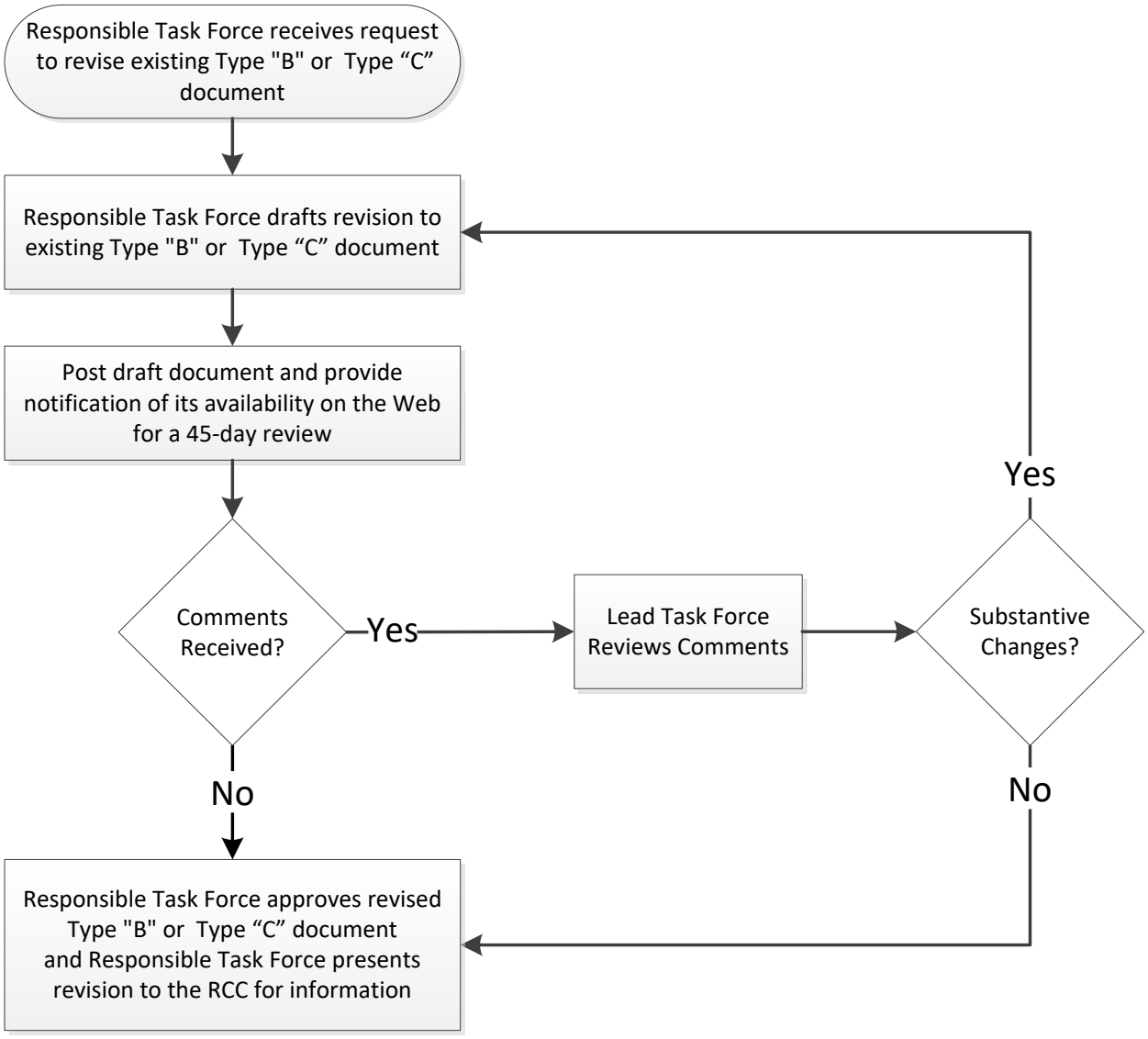
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



APPENDIX A - DIRECTORY FORMAT TEMPLATE

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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

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

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

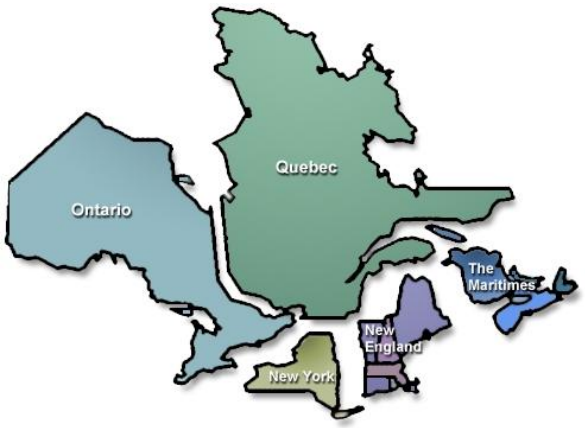
Redlined for RSC Review
December 7, 2017

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines, and Procedures



Approved by the Reliability Standards Committee

October Month 26xx, 2011 2017

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2017	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL

Table of Contents

I. EXECUTIVE SUMMARY 6
II. BACKGROUND 7
III. APPLICABILITY OF NPCC CRITERIA 8
IV. TASK FORCE ROLES AND RESPONSIBILITIES 8

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 9
1. NEW DIRECTORY 9
2. DIRECTORY REVISIONS 13
a. Revisions to the Criteria Section of a Directory 13
b. Revisions to the Appendix Section of a Directory 17
c. Revisions To The NPCC Glossary Of Terms 21
d. Withdrawal Of Revision Requests 24
3. DIRECTORY RETIREMENT 24
4. MAINTENANCE OF LINKS AND ERRATA 24
VI. DIRECTORY CLARIFICATION PROCESS 25
a. Request for Criteria Clarification 25
B. APPEALS 29
VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL 29
VIII. DIRECTORY FORMAT AND VERSION CONTROL 30
IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 30
APPENDIX A - DIRECTORY FORMAT TEMPLATE 1
APPENDIX B – NPCC REQUEST FOR CLARIFICATION 0
~~I. EXECUTIVE SUMMARY ..... 33~~
~~II. BACKGROUND ..... 44~~
~~III. APPLICABILITY OF NPCC CRITERIA ..... 55~~
~~IV. TASK FORCE ROLES AND RESPONSIBILITIES: ..... 55~~
~~V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE ..... 66~~
~~1. NEW DIRECTORY ..... 66~~
~~2. DIRECTORY REVISIONS ..... 88~~
~~a. Revisions to the Criteria Section of a Directory ..... 88~~
~~b. Revisions to the Appendix Section of a Directory ..... 1010~~
~~c. Revisions To The NPCC Glossary Of Terms ..... 1212~~
~~d. Withdrawal Of Revision Requests ..... 1515~~
~~3. DIRECTORY RETIREMENT ..... 1515~~
~~4. MAINTENANCE OF LINKS AND ERRATA ..... 1515~~
~~VI. DIRECTORY CLARIFICATION PROCESS ..... 1616~~
~~a. Request for Criteria Clarification ..... 1616~~
~~B. APPEALS ..... 1918~~
~~VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL ..... 1918~~
~~VIII. DIRECTORY FORMAT AND VERSION CONTROL ..... 1918~~

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 2019
X. REFERENCES: 2222
APPENDIX A DIRECTORY FORMAT TEMPLATE 1
APPENDIX B NPCC REQUEST FOR CLARIFICATION 1
APPENDIX C NPCC OPEN PROCESS FOR REGIONAL RELIABILITY CRITERIA DEVELOPMENT AND REVIEW .....
I. EXECUTIVE SUMMARY 3
II. BACKGROUND 4
III. APPLICABILITY OF NPCC CRITERIA.....5
IV. TASK FORCE ROLES AND RESPONSIBILITIES 5
V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE.....6
1. NEW DIRECTORY 6
2. DIRECTORY REVISIONS 8
a. Revisions to the Criteria Section of a Directory 8
b. Revisions to the Appendix Section of a Directory 10
c. Revisions to the NPCC Glossary Of Terms 12
d. Withdrawal of Revision Requests 15
3. DIRECTORY RETIREMENT 15
4. MAINTENANCE OF ERRATA AND LINKS.....15
VI. DIRECTORY CLARIFICATION PROCESS 16
a. Request for Criteria Clarification 16
b. Appeals 18
VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY MANUAL ..18

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~~VIII. DIRECTORY FORMAT AND VERSION CONTROL ..... 19~~

~~IX. REFERENCES: ..... 19~~
~~APPENDIX A – DIRECTORY FORMAT TEMPLATE ..... 20~~
~~APPENDIX B – NPCC REQUEST FOR CLARIFICATION ..... 24~~

I. EXECUTIVE SUMMARY

~~The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC") is to enhance the reliability of the international, interconnected bulk power system in Northeastern North America through the development of more stringent and regionally specific criteria.~~

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the~~–~~ NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.~~.~~

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.~~.~~

Commented [HS1]: Here is what the website says about NPCC and its mission. Not sure all of this is needed, but this sentence leaves the impression the only mission is to" enhance the reliability".

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c) (6) not-for-profit corporation in the state of New York responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC carries out its mission through (i) the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability, (collectively, "regional entity activities"), and (ii) the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, "criteria services activities"). NPCC provides the functions and services for Northeastern North America of a cross-border regional entity through its regional entity division, as well as regionally-specific criteria services for Northeastern North America through its criteria services division.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures;- within each Directory NPCC's reliability criteria has been reviewed and translated to ~~insure~~ ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type -"B" -and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. ~~Consistent with NPCC Document A-01 *Criteria for Review and Approval of Documents* t~~The ~~purpose of an~~ Appendix ~~continues to~~ supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

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Commented [HS2]: Since A-01 will not exist anymore, this sentence does not make sense at this point.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "~~-~~B~~-~~" Guidelines and "~~-~~C"~~-~~ Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC~~-~~ style requirements which will promote the NPCC regional criteria as more specific or more stringent within each

Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A" Criteria, "B" Guideline, or "C" Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices. A link to the Directory Flowchart and the Directory Mapping documents is provided in the References section of this manual.

The existingMost of NPCC's Several "B" Guideline and "C" Procedure documents have either beenwere transferred to Directories as Appendices in support of the relevant criteria. or wilThose B and C documents that were not incorporated into a Directory transferred l remain ed as standalone "B" Guideline and "C" Procedure documents. at the conclusion of the Directory project.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Mmemberexternal tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements. NPCC will not enforce compliance to the NPCC Directory requirements on any entity that is not an NPCC Full Member.

Commented [HS3]: I do not think it is necessary to state what NPCC will not do

IV. TASK FORCE ROLES AND RESPONSIBILITIES:

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With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination

between Task Forces is necessary. ~~the jurisdictional boundaries of Task Force ownership have been crossed and additional guidance when coordinating Directory review among Task Forces is necessary.~~

Commented [HS4]: Do we really mean areas of responsibility of Task Forces have been crossed? Jurisdictional seems to not be the right word to me.

In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the ~~References~~References section of this manual.

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The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. Directory Development and Revision Procedure

1. New Directory

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a

new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP. After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the ~~45 day~~45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA

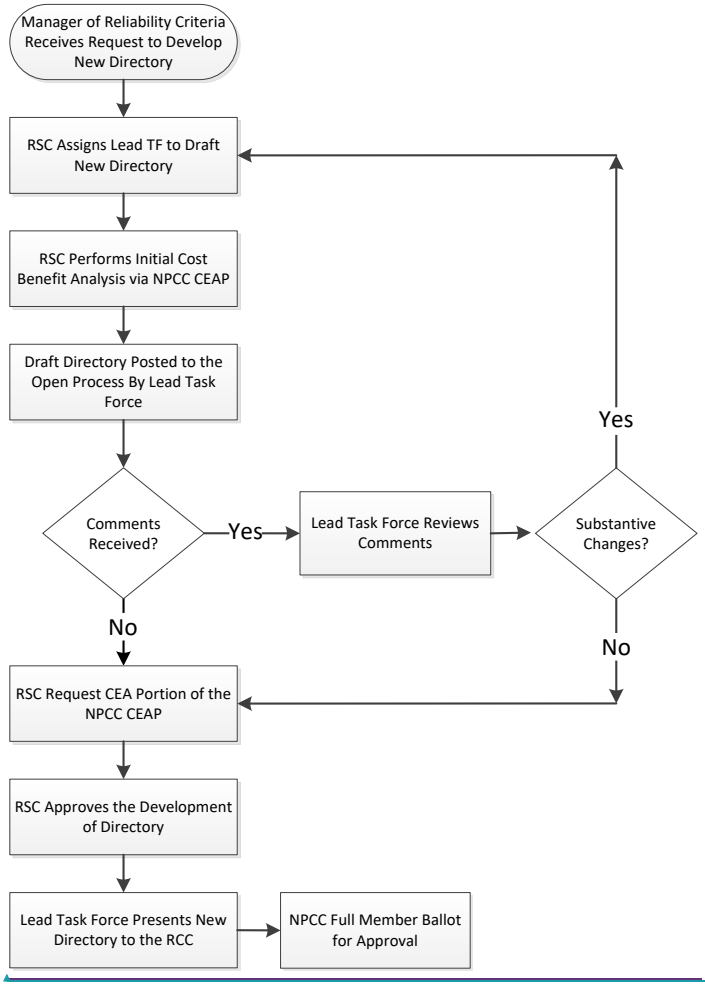
If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory. After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

Figure 1: New Directory

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.



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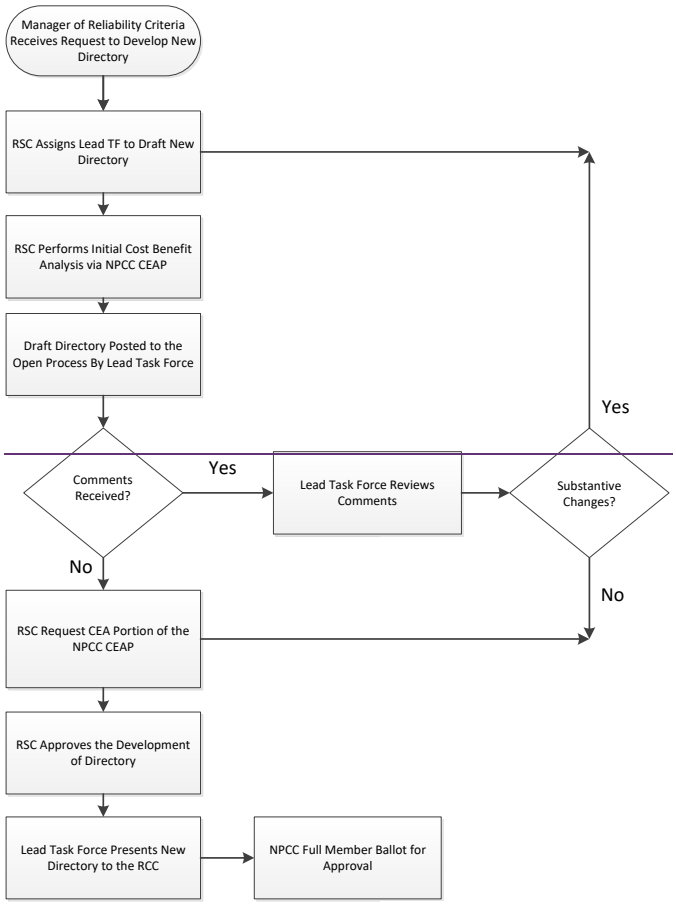

Manager of Reliability Criteria Receives Request to Develop New Directory
RSC Assigns Lead TF to Draft New Directory
RSC Performs Initial Cost Benefit Analysis via NPCC CEAP
Draft Directory Posted to the Open Process By Lead Task Force
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
RSC Request CEA Portion of the NPCC CEAP
RSC Approves the Development of Directory
Lead Task Force Presents New Directory to the RCC
NPCC Full Member Ballot for Approval

2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In ~~general~~general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

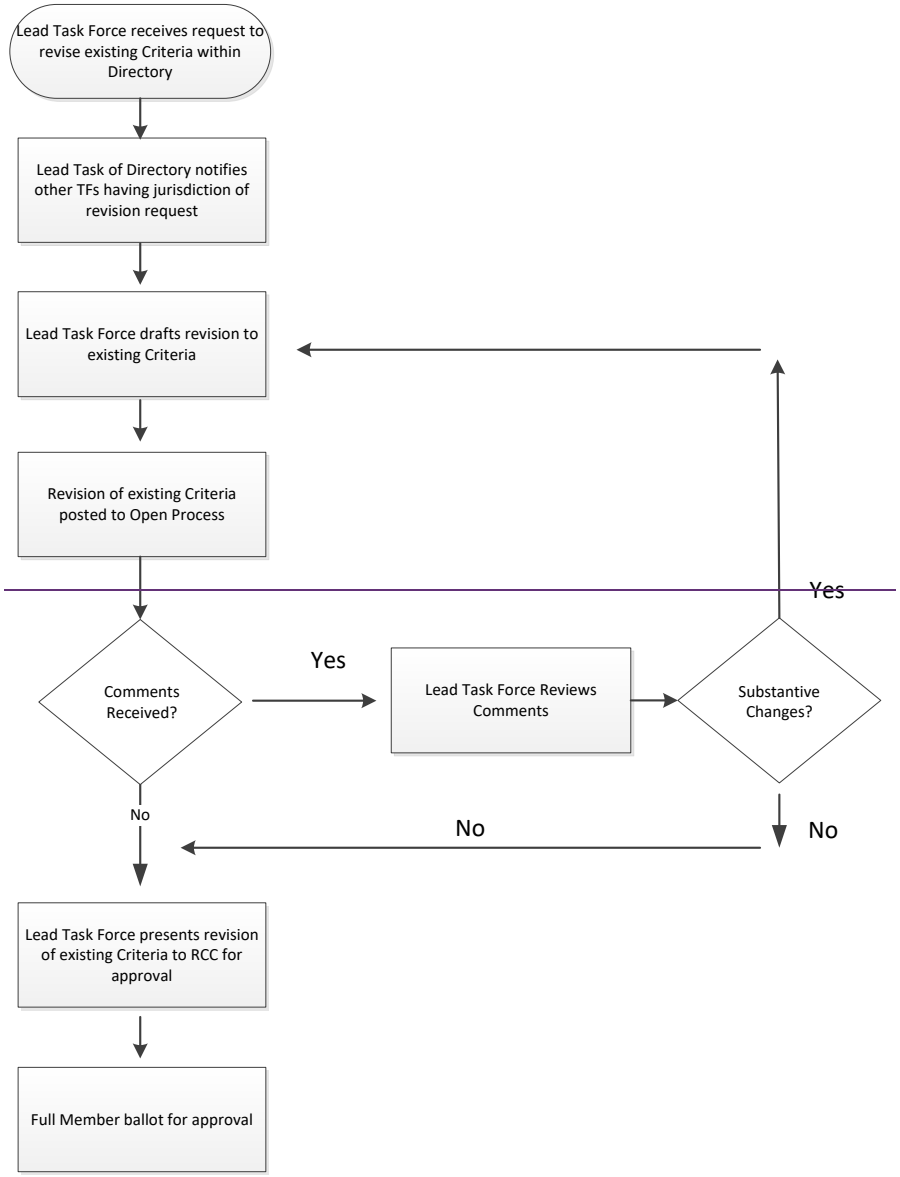
At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

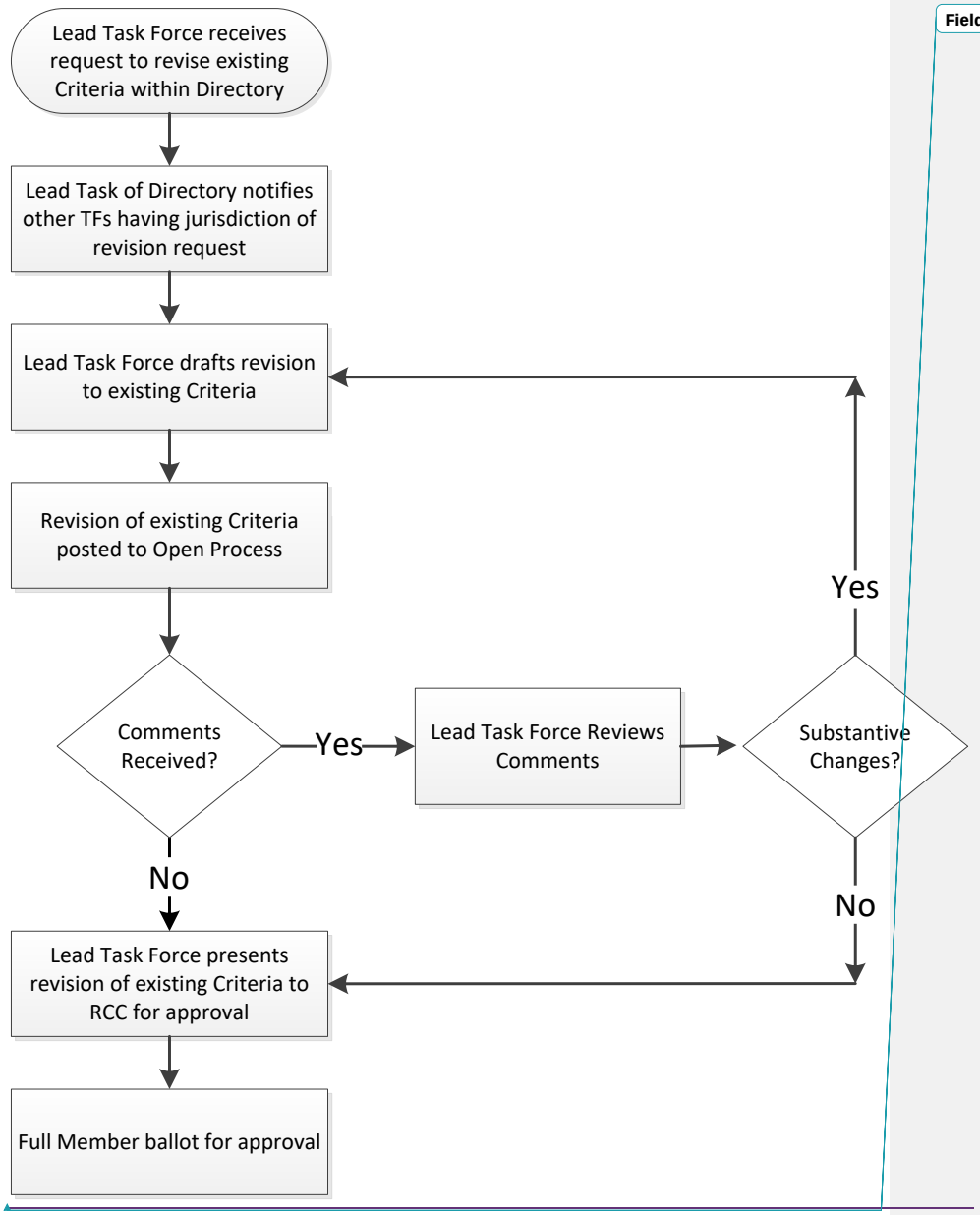
Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria


Lead Task Force receives request to revise existing Criteria within Directory
Lead Task of Directory notifies other TFs having jurisdiction of revision request
Lead Task Force drafts revision to existing Criteria
Revision of existing Criteria posted to Open Process
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
No
Lead Task Force presents revision of existing Criteria to RCC for approval
Full Member ballot for approval



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b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised or retired. Revisions or retirements of Appendices shall only require Task Force approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

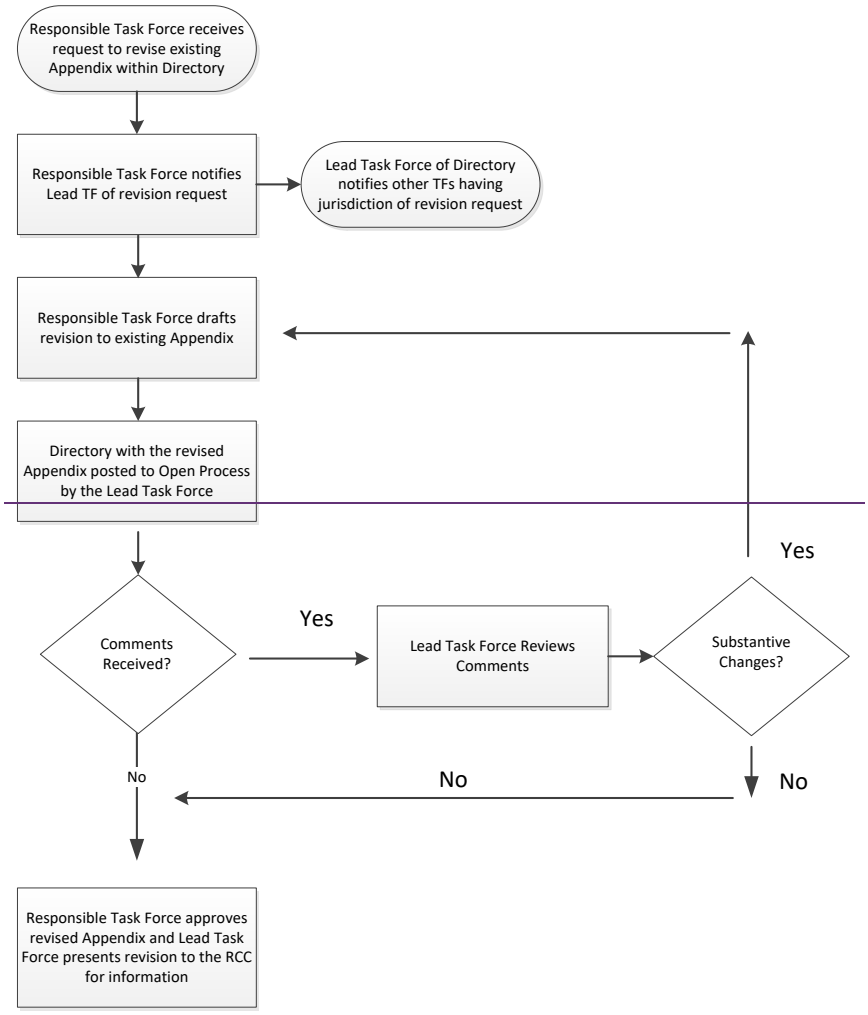
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

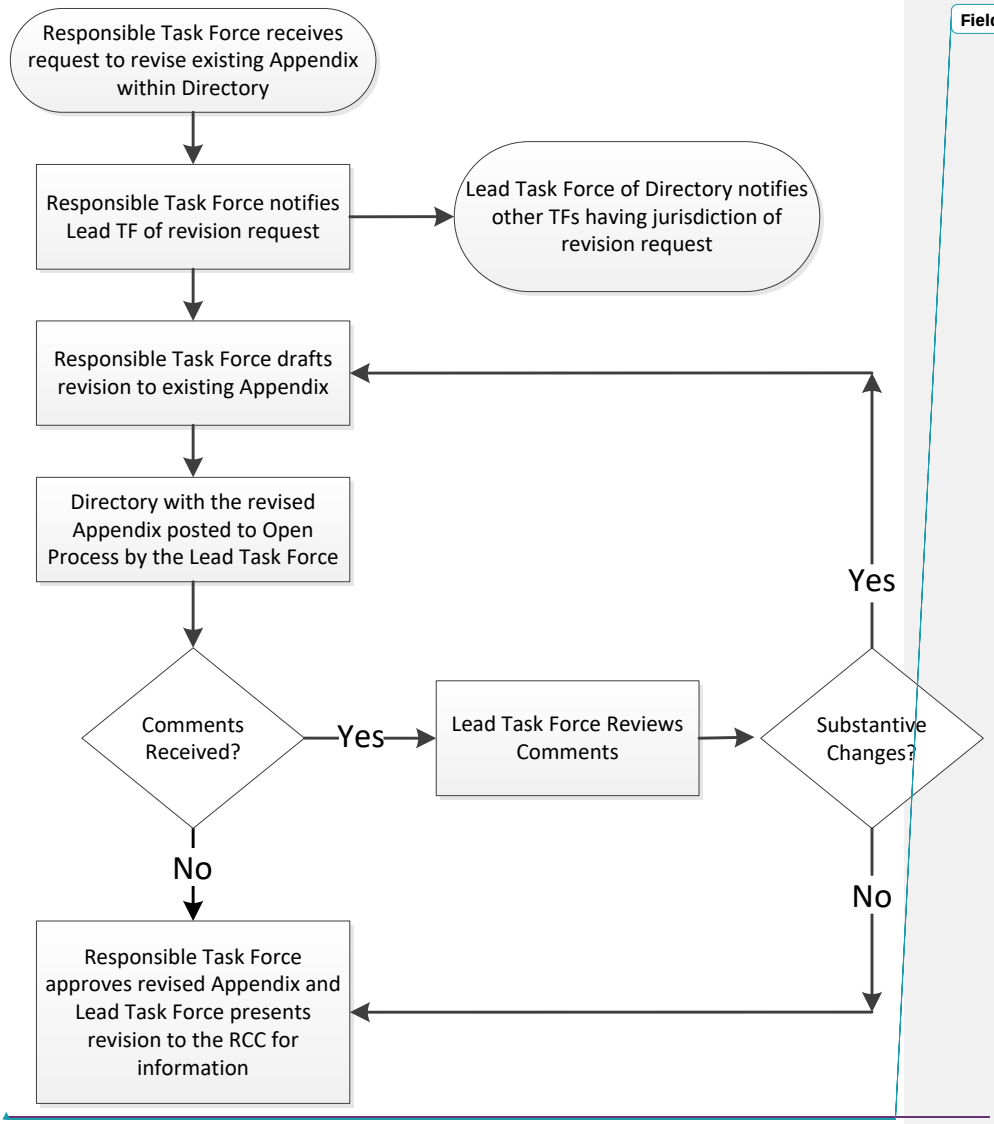
At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix. If the responses to the comments received on the revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive ~~45 day~~45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices


Responsible Task Force receives request to revise existing Appendix within Directory
Responsible Task Force notifies Lead TF of revision request
Lead Task Force of Directory notifies other TFs having jurisdiction of revision request
Responsible Task Force drafts revision to existing Appendix
Directory with the revised Appendix posted to Open Process by the Lead Task Force
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
No
Responsible Task Force approves revised Appendix and Lead Task Force presents revision to the RCC for information



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c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In ~~general~~general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

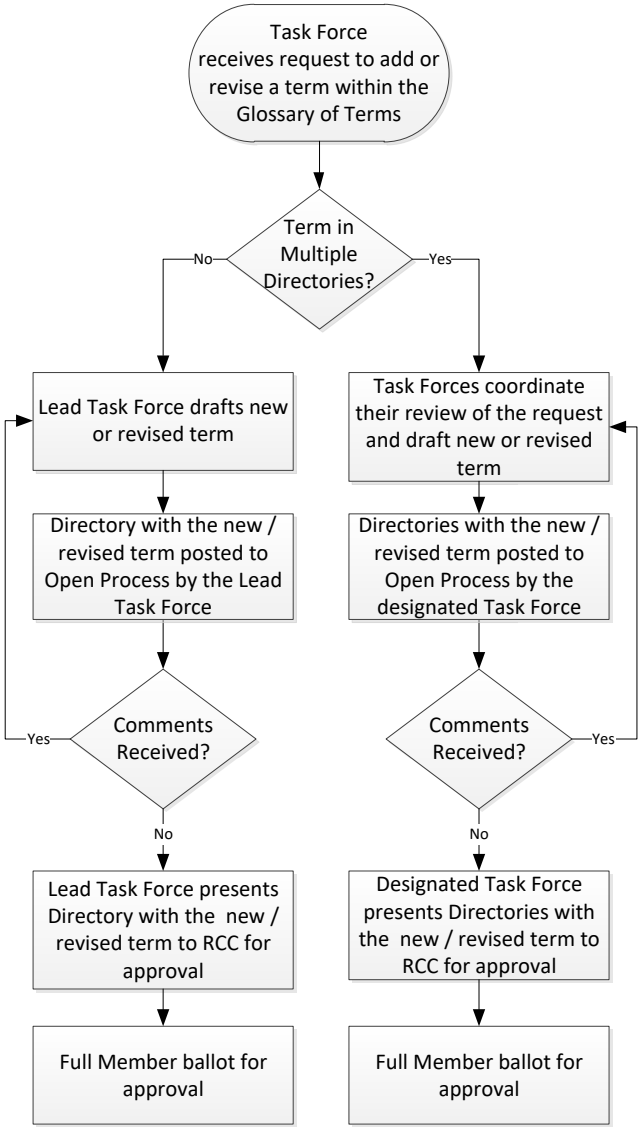
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the ~~45 day~~45-day Open Process, if responses to~~-~~ comments received on the new or revised term result in further~~-~~ substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. DIRECTORY RETIREMENT

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

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. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. MAINTENANCE OF LINKS AND ERRATA

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

[2] The Request for Clarification Form is included in Appendix B of this document.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

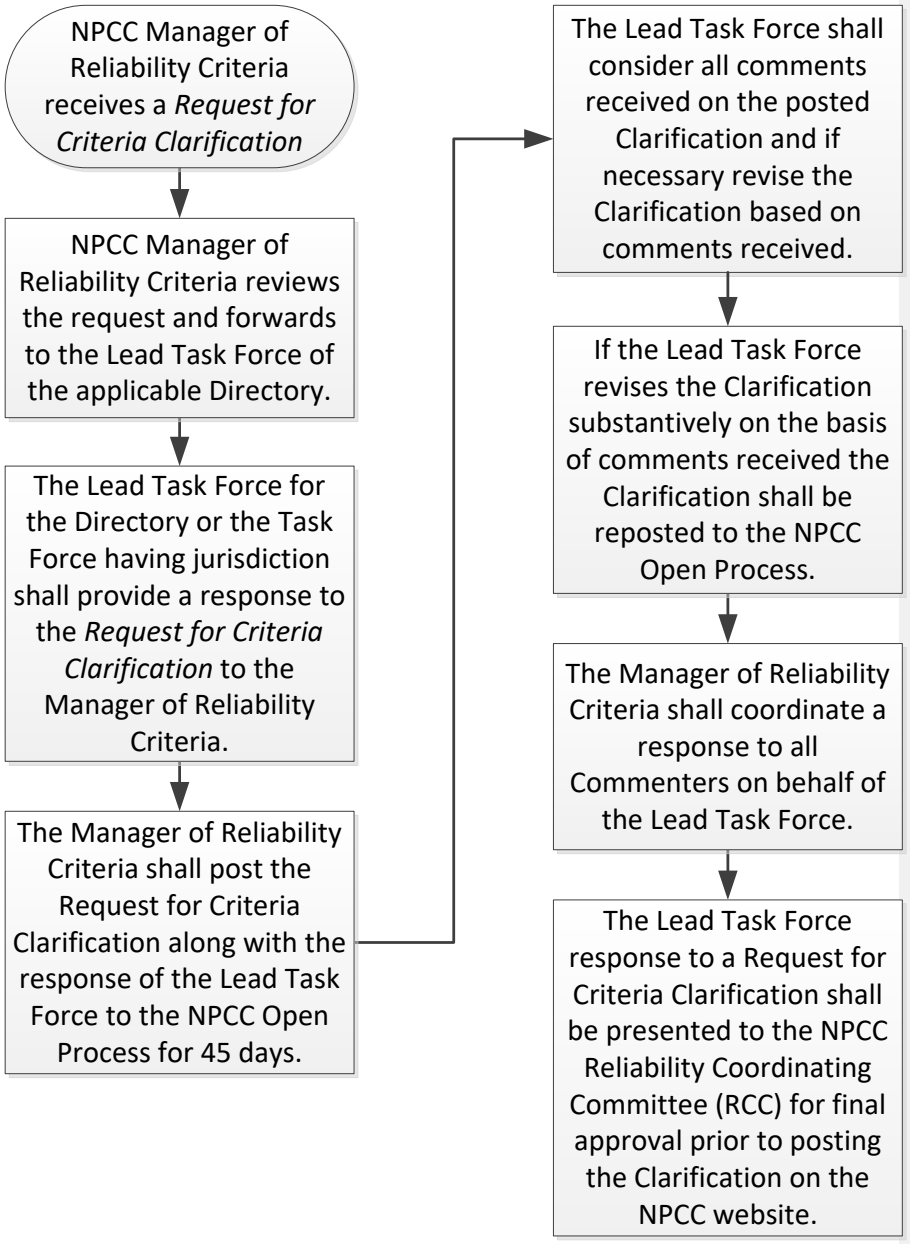
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ~~insure~~ ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification


NPCC Manager of Reliability Criteria receives a *Request for Criteria Clarification*
NPCC Manager of Reliability Criteria reviews the request and forwards to the Lead Task Force of the applicable Directory.
The Lead Task Force for the Directory or the Task Force having jurisdiction shall provide a response to the *Request for Criteria Clarification* to the Manager of Reliability Criteria.
The Manager of Reliability Criteria shall post the Request for Criteria Clarification along with the response of the Lead Task Force to the NPCC Open Process for 45 days.
The Lead Task Force shall consider all comments received on the posted Clarification and if necessary revise the Clarification based on comments received.
If the Lead Task Force revises the Clarification substantively on the basis of comments received the Clarification shall be reposted to the NPCC Open Process.
The Manager of Reliability Criteria shall coordinate a response to all Commenters on behalf of the Lead Task Force.
The Lead Task Force response to a Request for Criteria Clarification shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the Clarification on the NPCC website.

b. APPEALS

Any NPCC Full Member that has submitted a ***Request for Clarification*** may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL

The NPCC Directory Development and Revision Manual will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

VIII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.*
The Directory Project has consolidated most NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents into the Directories.

This ~~Criteria~~section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining -NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents.
~~NPCC documents have been divided into three categories, Document Type "A", Type "B" and Type "C". (See Appendix A for Process Flow Diagram and detailed description of process steps)~~

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member ~~Representatives,~~Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force- on a periodicity~~frequency~~ to be determined by the lead Task Force or initiated at the request

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of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. ~~Acceptance is determined~~implied ~~if no comments are received by NPCC. Comments are submitted through the NPCC web site.~~ The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval. ~~This final ballot approval will be conducted either at a scheduled RCC meeting or via email and electronic ballot.~~

In its~~-~~ review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot~~vote~~, with a recommendation for its adoption. Approval of ~~an~~ NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes. See Appendix C for further details on the entire NPCC Open Process.

For ~~new or~~ modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for non-compliance issues.

Commented [HS5]: The periodicity may also come from the document not the committee. For instance A-10.

Commented [HS6]: "implied" is too loose

Commented [GJD7]: I don't think this sentence is necessary.

Commented [GJD8]: Not necessary.

Commented [HS9]: In the judgment of the TF? Should we do something more along the lines of "errata" rules.

Commented [GJD10]: Not necessary.

Commented [QDL11]: Is it still possible to add a 'new' "A" document? If not this can be deleted.

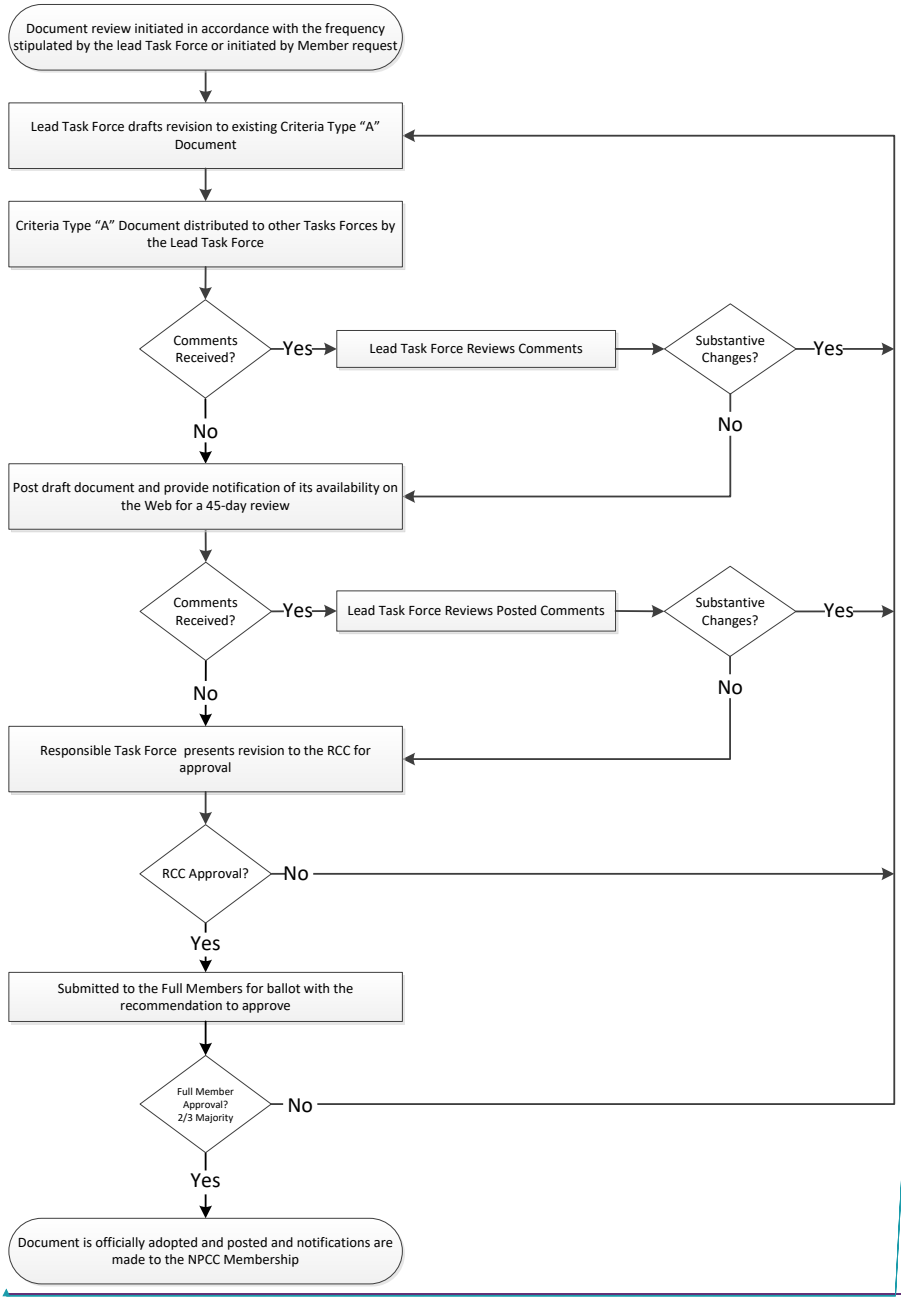
Gerry's comment….I recommend retaining…..although unlikely it is possible.

Commented [HS12]: How about relative to implementation schedules, rather than non-compliance.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Commented [GJD13]: This chart is excellent Quintin….however one suggested change:

In the case of an A Criteria document revision….. the Lead TF is generally the only TF involved….unlike a Directory where the Lead TF of the Directory may need to coordinate the review with other TF's who have jurisdiction over an Appendix in the Directory.

Accordingly, I think this flow chart can be tightened up a bit.

No need to distinguish between Lead TF and responsible TF since they are one in the same.

.

Field Code Changed

Document~~s~~: Guideline ~~-~~ Type "B" and Procedure-Type "C"

General Description

Type "B" documents~~, with approval by the Reliability Coordinating Committee,~~ are ~~the guides or~~ guideline documents~~s for the achievement of acceptable system performance which implement criteria of Type "A" documents~~.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type "B" or a Procedure-Type "C" document be revised or retired. Revisions or retirements of Guideline-Type "B" or Procedure-Type "C" documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type "B" or a Procedure-Type "C" document shall be submitted to the Task Force responsible for the document. ~~The Task Force responsible for the document shall notify the Lead Task Force that a request to revise or retire the document has been received.~~

~~The Lead Task Force shall be responsible for notifying all Task Forces which have jurisdiction over the document that a request to revise or retire the document has been received.~~

~~After the Task Force responsible for the document reviews the subject document they will forward the draft revised document to the Lead Task Force.~~ The ~~Lead~~ Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days. ~~The Lead Task Force will limit the comments solicited to only the subject document.~~

The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45~~-~~-day posting.

At the conclusion of the ~~45-day~~ Open Process, the ~~Lead~~ Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate.~~will forward the comments submitted on the document to the Task Force responsible for the revised or retired document.~~ If the ~~responses to the~~ comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-

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Commented [GJD14]: I notice we didn't describe 'retiring' an A Criteria document in the section above.

Seems inconsistent…and I think we should address.

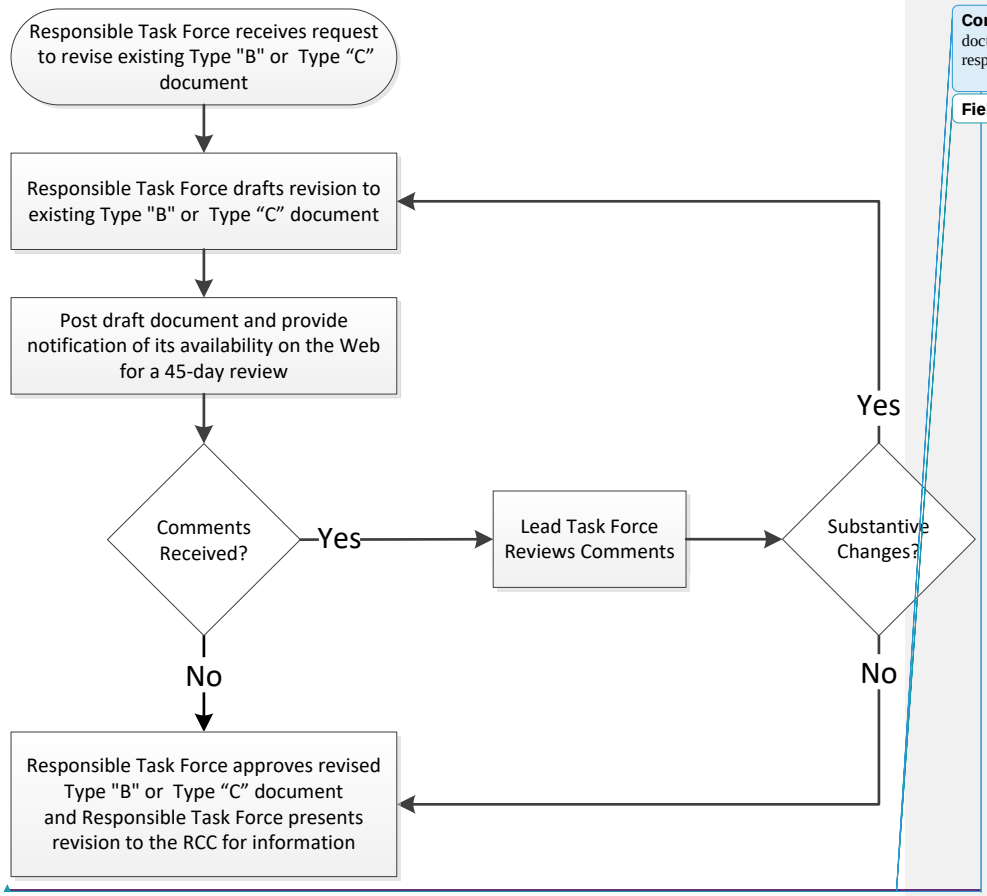
Commented [GJD15]: Again in the case of standalone B and C documents there is no distinction between Lead TF and the TF responsible for the document….they are the same.

day review period by the ~~Lead~~ Task Force responsible for the document.~~.~~ Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The ~~lead~~ Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type "C" Documents



Commented [GJD16]: Again in the case of standalone B and C documents there is no distinction between Lead TF and the TF responsible for the document….they are the same.

Field Code Changed

~~Type "B" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "B" document is presented by the lead Task Force to the Reliability Coordinating Committee for~~

approval either at a scheduled RCC meeting or via email and electronic ballot. The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list. See Appendix C for further details on the entire NPCC Open Process.

Should the RCC determine that the document cannot be approved the RCC will return the document to the lead Task Force.

Members may request the lead Task Force, at any time, to review and revise the Guidelines, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.

Document, Procedure Type "C"

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General Description

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements of Type "A" and "B" documents.
Review and Approval

Type "C" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site.

The lead Task Force may invoke an expedited posting period for a "C" document if necessary to address implementation issues as identified by the lead Task Force.

Expedited postings will be for no less than 30 days.

The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required which would require an additional posting(s), the Type "C" document will be considered and voted on for final approval by the lead Task force and is then distributed for informational purposes to the Reliability Coordinating Committee and the other Task Forces. (Formal adoption by the Reliability Coordinating Committee or the NPCC Full Member Representatives is not required for Type "C" documents).

The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list with the next Reference Manual Revision. See Appendix C for further details on the entire NPCC Open Process.

The maintenance of Links, contact lists and the correction of errors found within NPCC documents ("A' Criteria, 'B' Guidelines and 'C' Procedures) shall be the responsibility of the NPCC Standards staff.

An error may be classified as Errata provided its correction does not change the scope or intent of the language.

Errata and Link revisions are updated as needed and require only the approval of the lead Task Force prior to publishing.

NPCC staff will also maintain a record of the change on the Record of Revision.

Members may request the lead Task Force, at any time, to review and revise the Procedures or References, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.

Lead Task Force: Task Force on Coordination of Planning

Reviewed for concurrence by: TFCO, TFSP, TFSS, CC, and TFIST

Review frequency: 4 years

IX. References:

1. https://www.npcc.org/Standards/Directories/Directory_Flowchart.pdf.
2. https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.
3. https://www.npcc.org/Library/NRAP/Forms/Public%20List.aspx

APPENDIX A - DIRECTORY FORMAT TEMPLATE

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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of ~~Non Compliance~~Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a ~~45 day~~45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

NPCC, Inc.

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

NPCC Request for Criteria Clarification

Note: ~~an~~An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

Appendix C – NPCC OPEN PROCESS FOR REGIONAL RELIABILITY CRITERIA DEVELOPMENT AND REVIEW

Step 1 Initiation of the Open Process Review (Boxes 1, 2, 3, and 4)

(Reference the, Figure 6 Flowchart at the end of this Appendix)

The NPCC Open Process for Regional Reliability Criteria Development and Review can be initiated a number of ways:

A comment is submitted through the Open Process on the NPCC web site identifying an issue that could initiate a review. *(Box 1)* **The Task Forces will review the comment and respond to it with a recommendation.** *(Box 2)*

An NPCC Member, Task Force, CC, or other party may identify a reliability need that is currently not addressed in the existing set of documents. *(Box 4)*

Once a NPCC Open Process for Review is initiated for a Document, it is identified and tracked in the NRAP Report. *(Box 3)*

Step 2 Document Review and Revision (Boxes 5, and 6)

The designated lead Task Force as identified in the NRAP or as charged by the Reliability Coordinating Committee (RCC) to draft a new document will develop it and build a consensus within the Task Force. *(Box 5)*

The document, once approved by the lead Task Force for public release, will be posted using the NPCC Open Process for a comment period. This comment period will begin once notification is made to the industry of the posting and comments will be accepted through the NPCC website for a period not to exceed 45 days. Notification will be given to neighboring Regions, whose reliability might be impacted by NPCC's Criteria, and their review of the proposed Criteria will be accommodated and submittal of their comments encouraged. *(Box 6)*

Step 3 Industry Comments on the Posted Document (Boxes 7, 8, 9, 10, 11, 12, 14, 15, 17, and 18)

The industry and neighboring Regions whose rReliability may be affected hiave 45 days to submit their comments to the proposed document. *(Box 7)*

At the end of the comment period the lead Task Force will review the comments and reach consensus on how to address the comments and decide whether further revision to the document is necessary. *(Box 8)* Also as part of this revision the lead Task Force must ascertain if the revisions are substantive enough to require another posting.. *(Box 11)*

- The lead Task Force will then post the responses to the comments received to the NPCC Open Process for industry review. *(Box 9)*

- The document is revised as necessary into a "final" draft. *(Box 10)*

- If the document is a *"C" (a Procedure)* document, the document is voted on by the lead Task Force and if not approved further work is required and notification is posted. *(Box 14, 15, 17 and 18)*

- *If the document is a "C" (a Procedure)* document *(Box 12)*, and approved by the lead Task Force, *go to Step 6 (Box 16)*

Step 4 Gaining other Task Force and RCC Approval (Documents "A" and "B" Type Criteria or Guidelines only) (Boxes 12a 13, 19-25)

- Following the posting of the Document, the affected Task Forces will arrange to review the document and approve it. *(Boxes 12a and 13)*

- If the document is not acceptable as is and further revision is requested the document will be returned to the lead Task Force with the specific recommended revisions. *(Box 19)*

~~This revision, if accepted by the lead Task Force, may result in another Open Posting and notifications to neighboring Regions whose reliability might be impacted. *(Box 20)*~~

~~If the NPCC Task Forces have all signified their acceptance and approval of the document, it will be forwarded to the RCC for its review. *(Box 21)*~~

~~The RCC will vote on the document at its next scheduled meeting and if there are issues outstanding, the RCC will make specific recommendations to the lead Task Force and request that further work be done. Notification is posted. *(Box 22, 23 and 24)*~~

~~*If the document is approved by the RCC and is a "B" Type, (a Guideline Document)(Box 25), go to Step 6 (Box 26)*~~

~~*Step 5 Gaining Full Member Representative Approval (Document "A" Type Criteria only) (Boxes 27, 28, 31, and 32)*~~

~~Upon approval of an "A Type" document by the RCC, the Document is submitted to the NPCC Full Member Representatives noting the recommendation by the RCC to approve. *(Box 27)*~~

As outlined in the NPCC By-Laws approval of an NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.. *(Box 28)*

If the document is not approved, any submitted comments by the Full Member Representatives will be forwarded along with the document back to the lead Task Force for further work and notification is posted. *(Box 31 and 32)*

Step 6 Document is Officially Adopted (All Documents) (Boxes 16, 26, 29, 30, 33, 34, and 35)

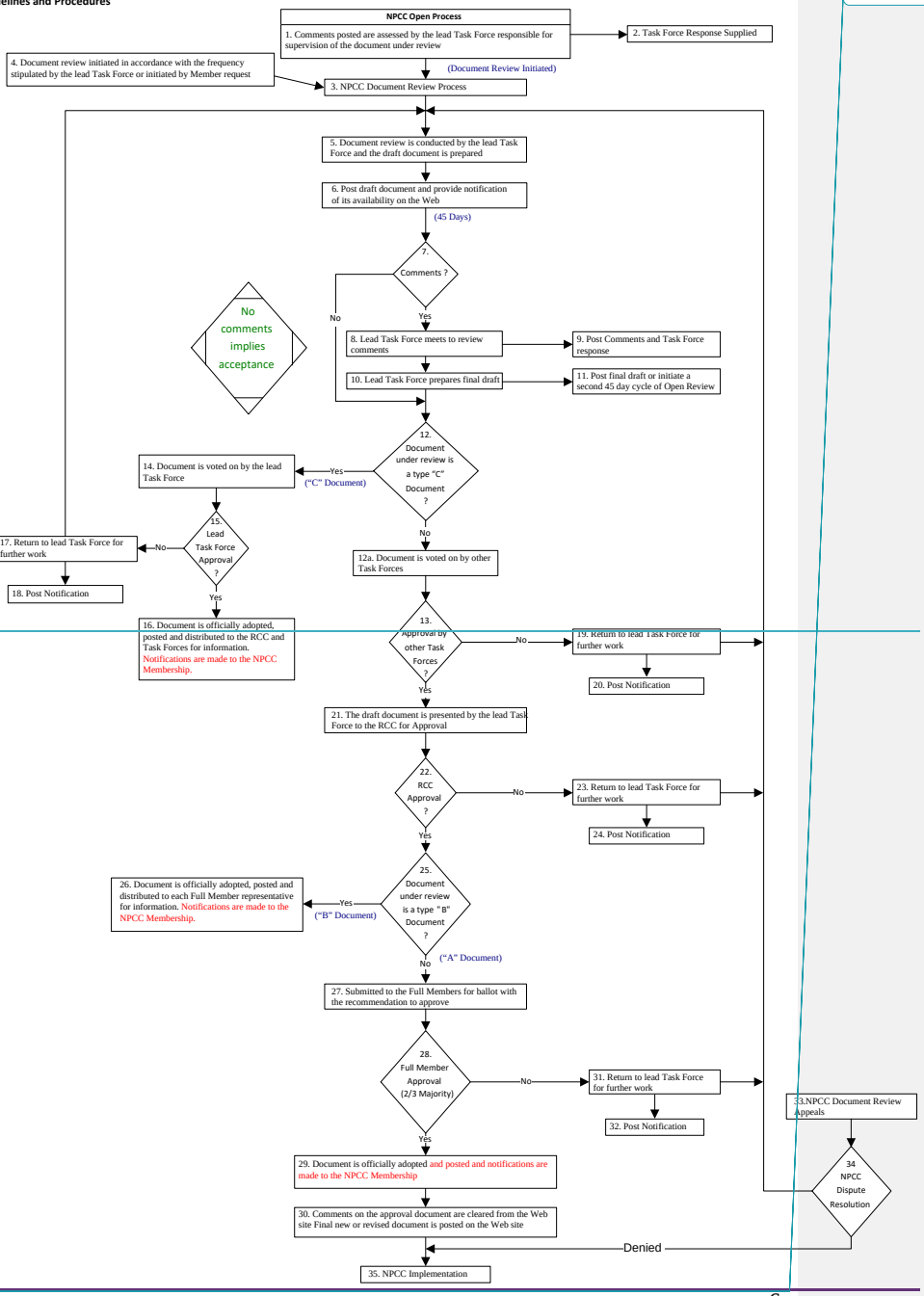
Document is officially adopted along with any implementation plan for compliance and notifications are made to the NPCC Membership. *(Boxes 16, 26, and 29)*

Document is posted on the public portion of the NPCC website, replacing the old document if a revision is made. NPCC Staff will also update the NRAP as required to show the next scheduled review date. *(Box 30)*

The requirements and procedures in the revised or new document are implemented, as stated in the implementation plan, or continued as required by the document. *(Box 35)*

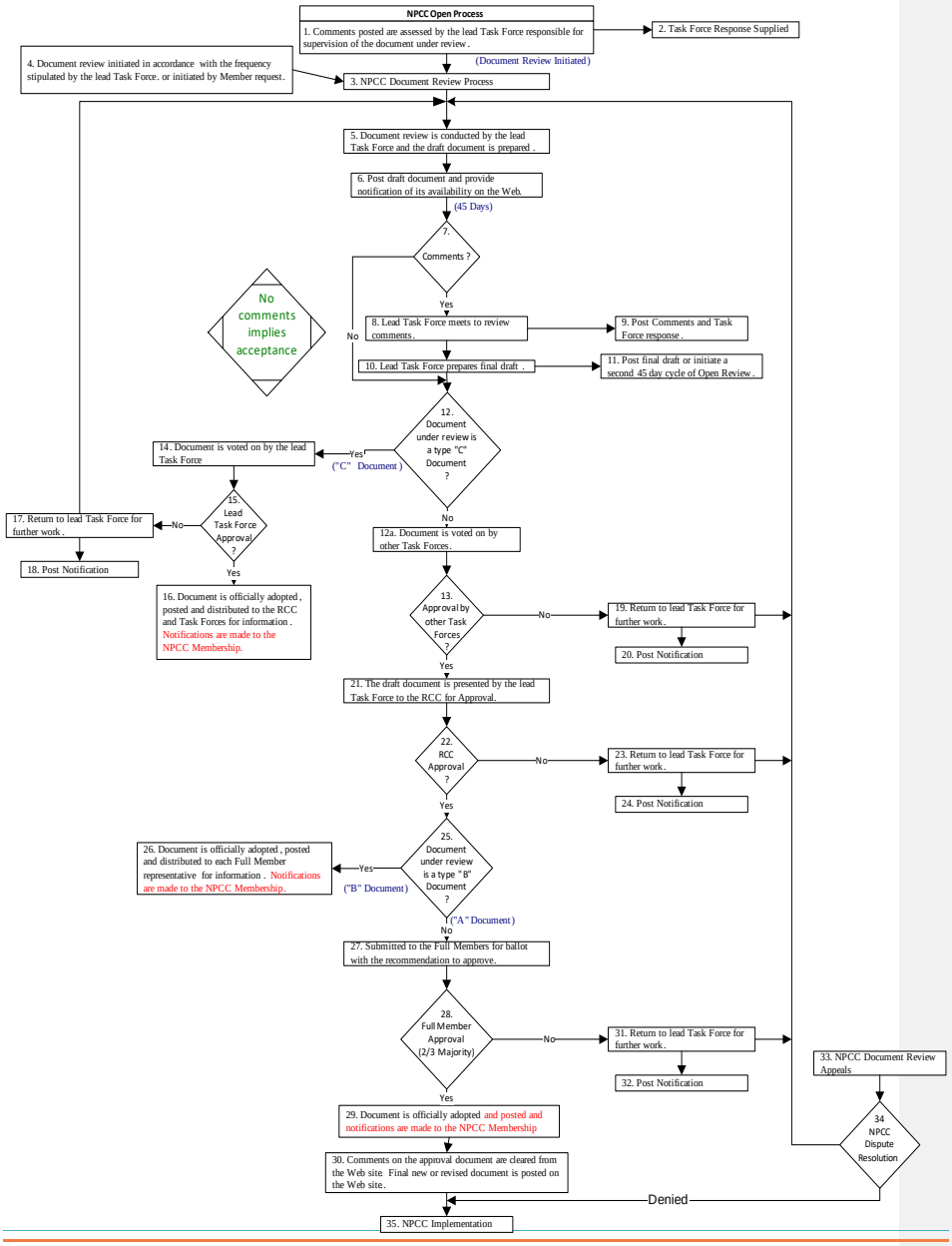
~~AT ANYTIME~~ANY TIME ~~DURING THE PROCESS AND PRIOR TO IMPLEMENTATION THE DOCUMENT IS SUBJECT TO THE NPCC DISPUTE RESOLUTION PROCESS. *(BOX 33 AND 34)*~~

NPCC Open Process of Criteria, Guidelines and Procedures



Field Code Changed

NPCC Open Process of
Criteria, Guidelines and Procedures



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

August 8, 2018

Members Regional Standards Committee:

Subject: Revised NPCC *Directory Development and Revision Manual* and Proposed Retirement of Document A-01 *Criteria for Review and Approval of Documents.*

Please find attached an updated version of the NPCC *Directory Development and Revision Manual* which has been revised to incorporate NPCC document A-01 *Criteria for Review and Approval of Documents* into the Manual in advance of formally retiring the A-01.

The A-01 document was established prior to the development of the NPCC Directories and its content is being incorporated into the Directory Manual to achieve document efficiency.

The Directory Manual has been reviewed and updated in accordance with its five-year review cycle and relevant sections of the A-01 have been incorporated into the Manual to facilitate the retirement of the A-01 document.

The revised Directory Manual was posted to the NPCC Open Process review from April 25 to June 9, 2018 and the RSC has considered comments received.

Contingent on RSC approval of the revised Directory Manual, the NPCC Task Force on Coordination of Planning (TFCP), which has jurisdiction over the A-01 document, has recommended retiring the A-01 document at its meeting on August 14 and 15, 2018.

Accordingly, the revised NPCC *Directory Development and Revision Manual* is presented to the RSC for approval.

Thank you.

Gerry Dunbar
Manager, Reliability Criteria
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NPCC, Inc.
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Clean
Open Process Comments Considered

August 8, 2018

Northeast Power Coordinating Council, Inc.
Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines, and Procedures

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL & PROCESS FOR THE REVIEW and APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

Table of Contents

I. EXECUTIVE SUMMARY 2

II. BACKGROUND 2

III. APPLICABILITY OF NPCC CRITERIA 4

IV. TASK FORCE ROLES AND RESPONSIBILITIES 4

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 5

1. NEW DIRECTORY 5

2. DIRECTORY REVISIONS 8

a. Revisions to the Criteria Section of a Directory 8

b. Revisions to the Appendix Section of a Directory 11

c. Revisions To The NPCC Glossary Of Terms 13

d. Withdrawal Of Revision Requests 16

3. DIRECTORY RETIREMENT 16

4. MAINTENANCE OF LINKS AND ERRATA 16

VI. DIRECTORY CLARIFICATION PROCESS 17

a. Request for Criteria Clarification 17

b. Appeals 19

VII. DIRECTORY FORMAT AND VERSION CONTROL 20

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES .....

IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES .....

APPENDIX A - DIRECTORY FORMAT TEMPLATE .....

APPENDIX B – NPCC REQUEST FOR CLARIFICATION .....

I. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and

translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC regional criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the References section of this manual.

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA.

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

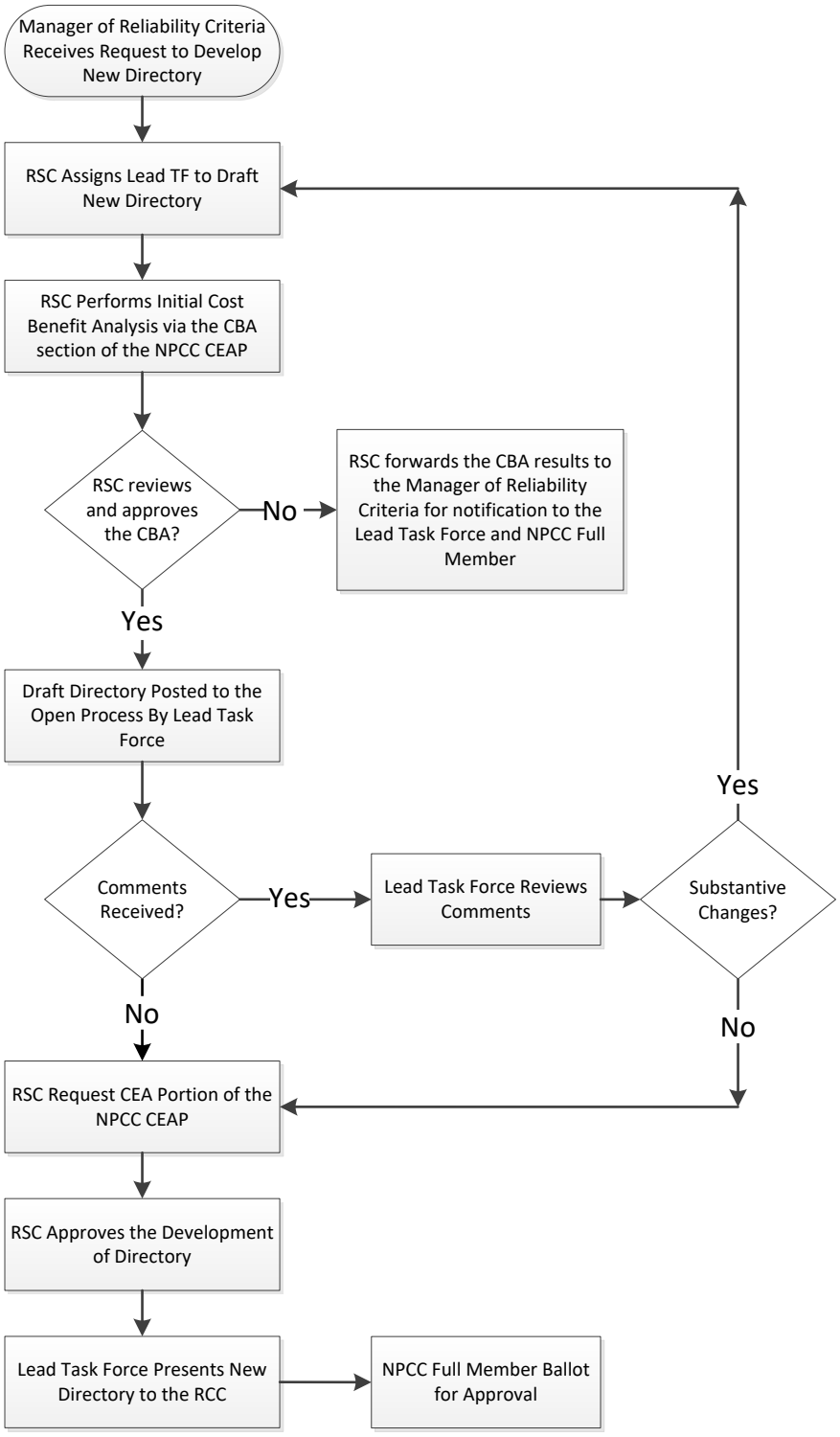
The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory.

After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

Figure 1: New Directory



2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

In accordance with the CBA section of the CEAP if the RSC concludes that the revision to an existing Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

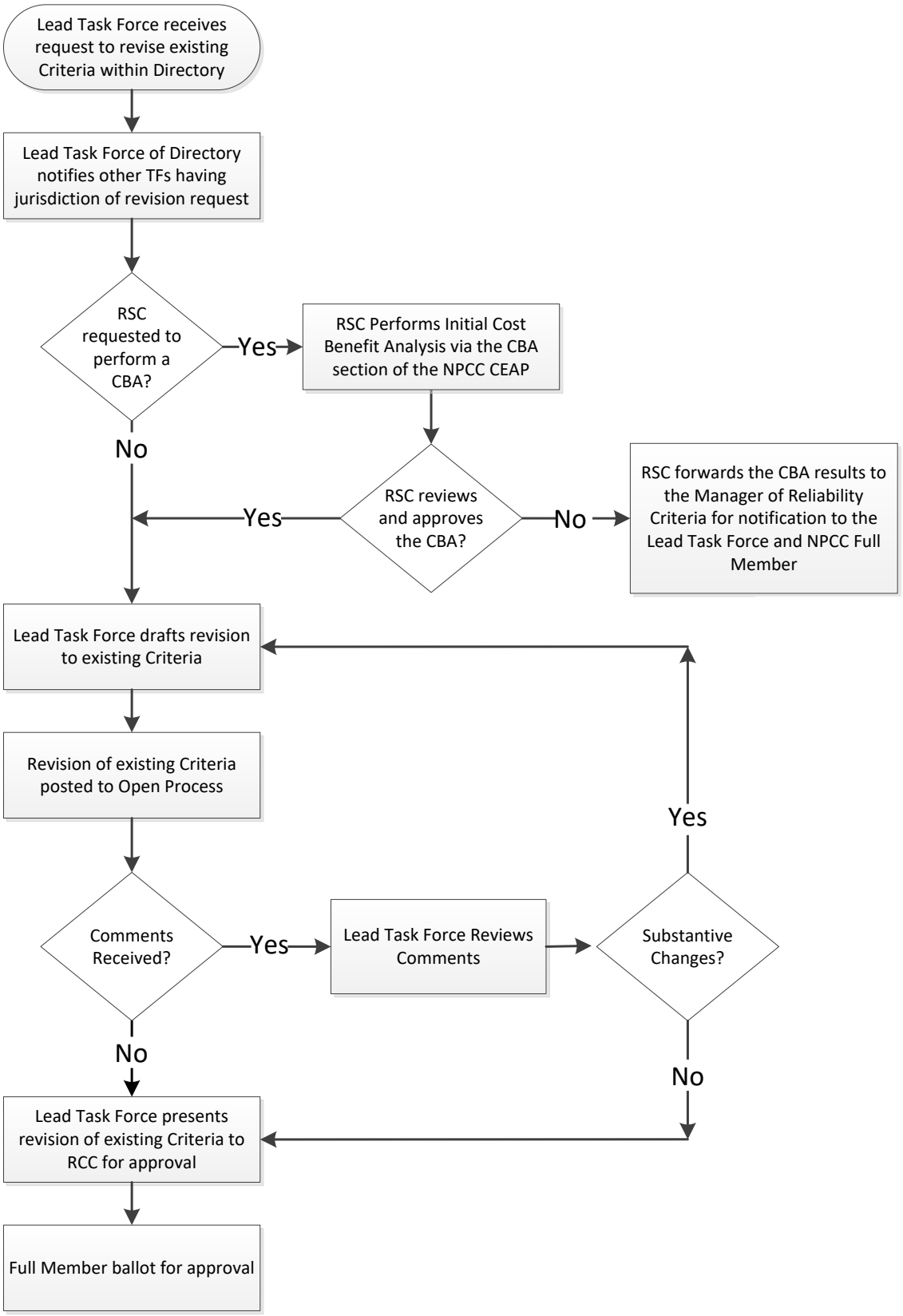
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised, added or retired. Revisions, additions or retirements of Appendices shall only require Task Force approval.

A request to revise, add or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise, add or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received.

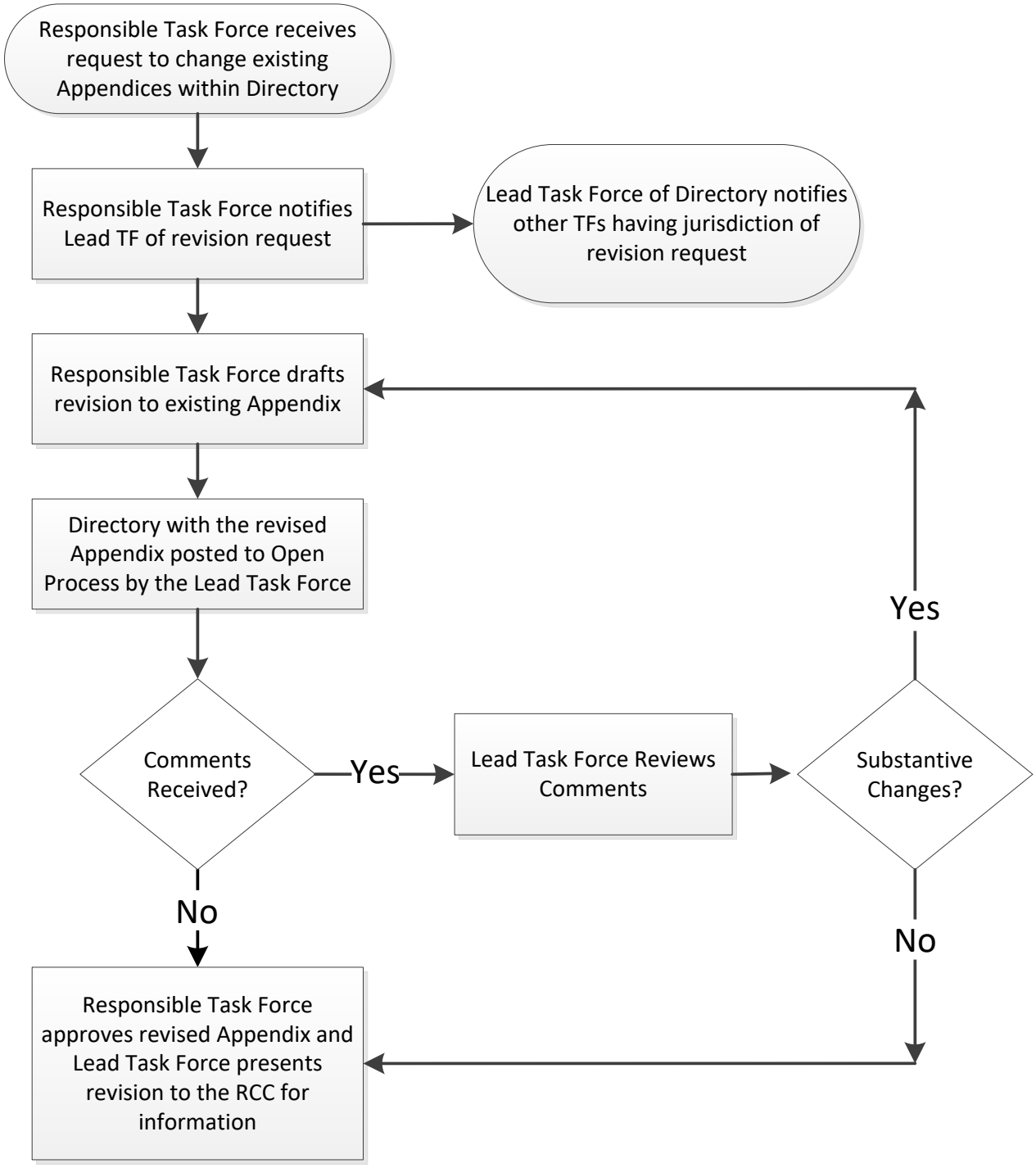
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the new, revised or retired Appendix. If the responses to the comments received on the new, revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the new, revised or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the new, revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the new, revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices



c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new or revised Glossary term is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

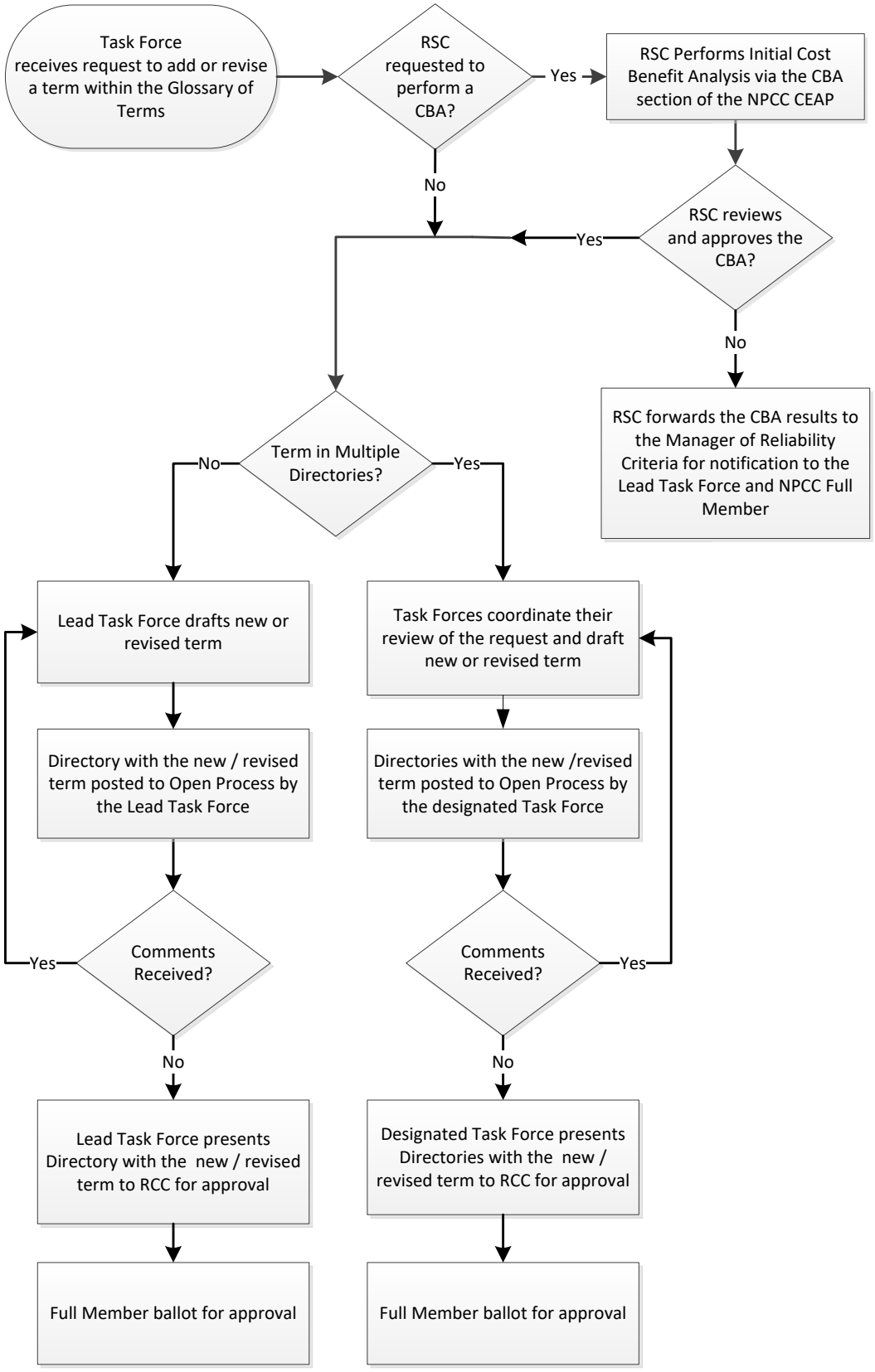
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. DIRECTORY RETIREMENT

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

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. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. MAINTENANCE OF LINKS AND ERRATA

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory

[2] The Request for Clarification Form is included in Appendix B of this document.

clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

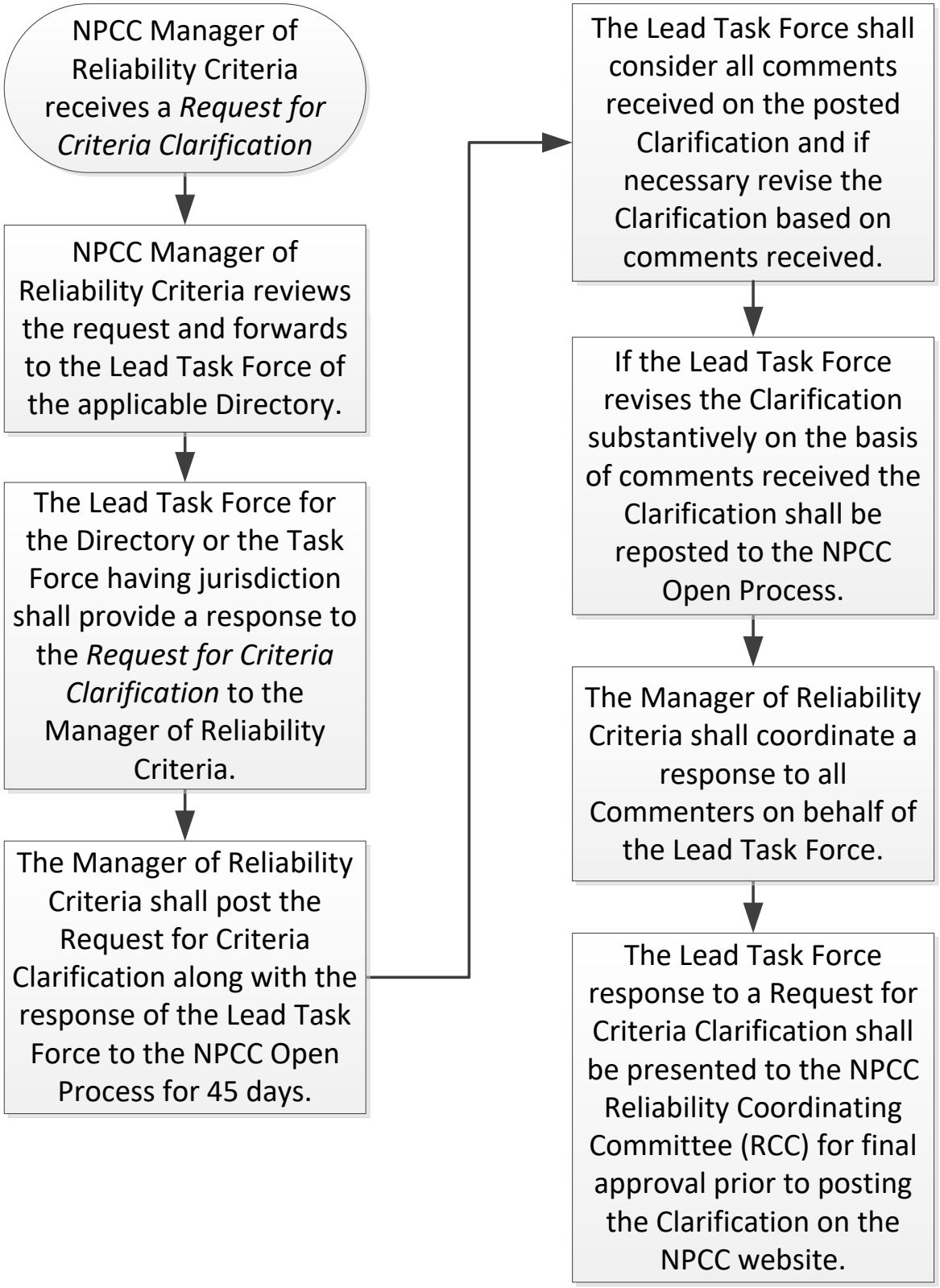
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

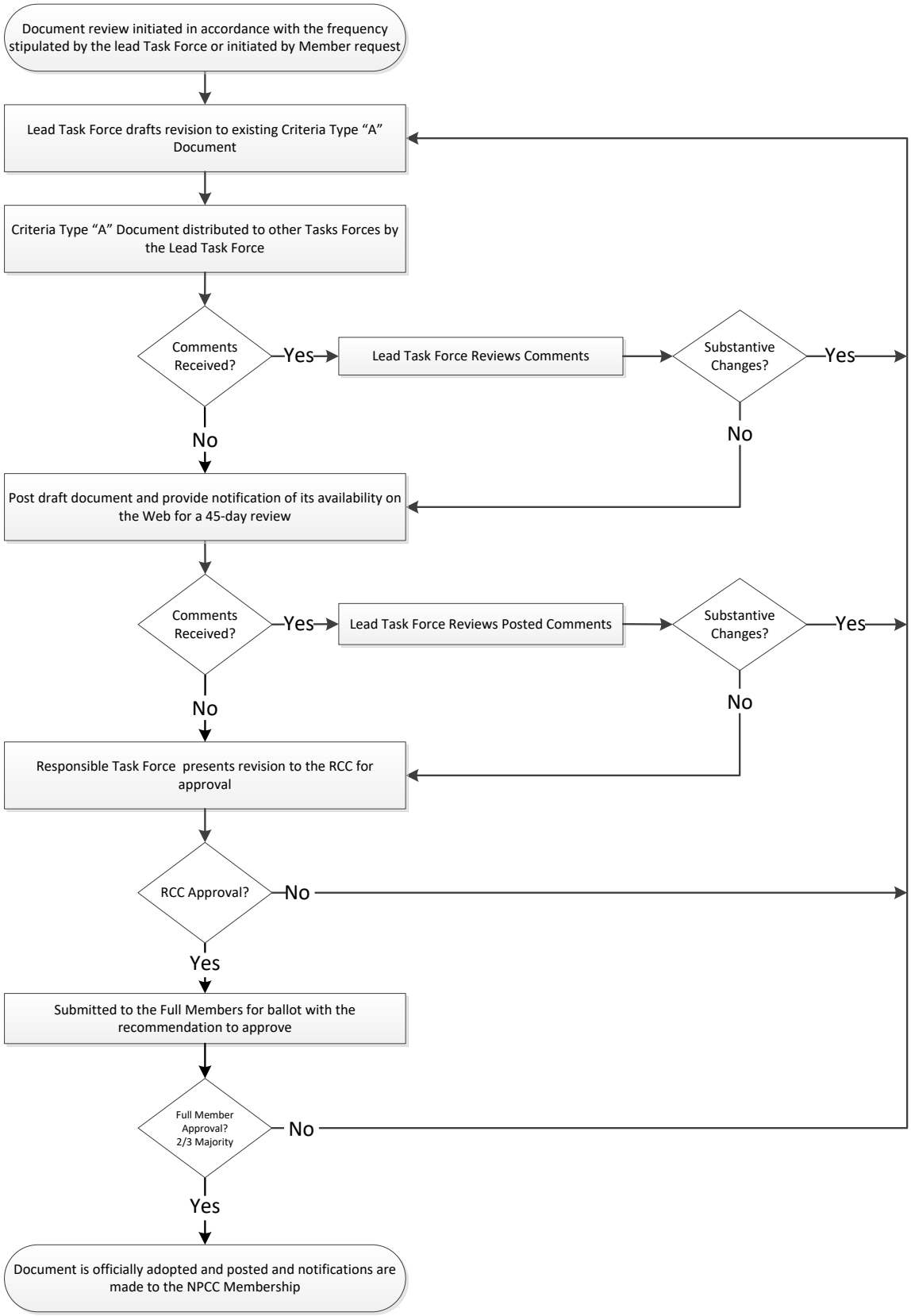
The approved and adopted Type “A” document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list.

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC “Appeals and Dispute Resolution Process” for non-compliance issues.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

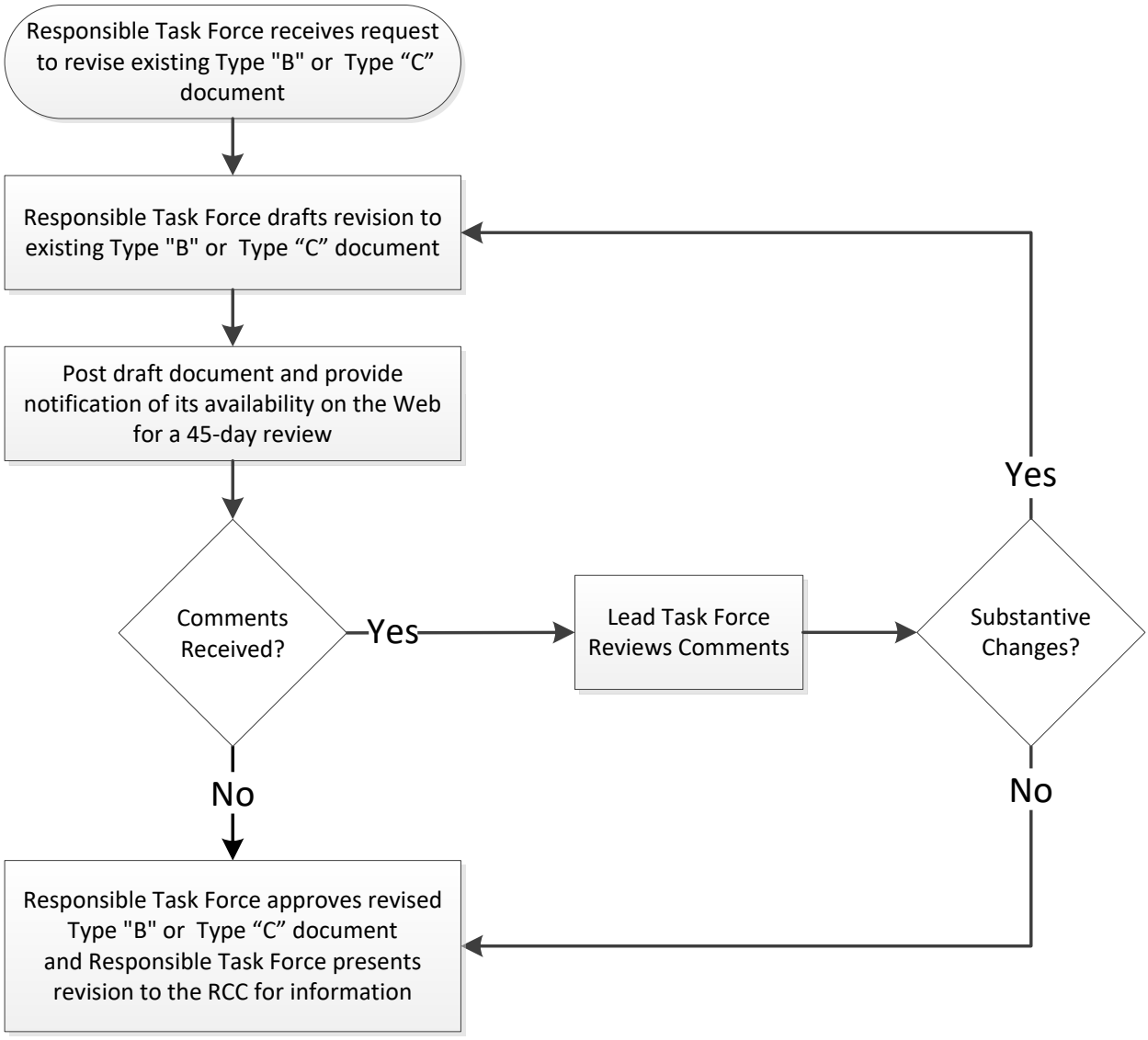
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to an existing Type "B" and “C”document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

APPENDIX A - DIRECTORY FORMAT TEMPLATE

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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

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

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

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

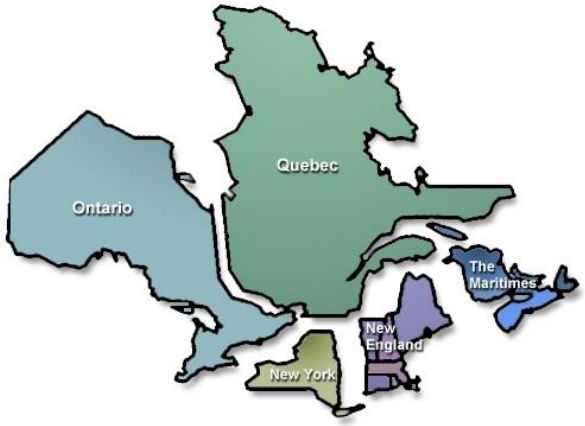
Redlined
Open Process Comments Considered

August 8, 2018

Northeast Power Coordinating Council, Inc. Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines, and Procedures



Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL
& PROCESS FOR THE REVIEW and APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

Table of Contents

I. EXECUTIVE SUMMARY 2

II. BACKGROUND 2

III. APPLICABILITY OF NPCC CRITERIA 4

IV. TASK FORCE ROLES AND RESPONSIBILITIES 4

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 5

1. NEW DIRECTORY 5

2. DIRECTORY REVISIONS 8

a. Revisions to the Criteria Section of a Directory 8

b. Revisions to the Appendix Section of a Directory 11

c. Revisions To The NPCC Glossary Of Terms 13

d. Withdrawal Of Revision Requests 16

3. DIRECTORY RETIREMENT 16

4. MAINTENANCE OF LINKS AND ERRATA 16

VI. DIRECTORY CLARIFICATION PROCESS 17

a. Request for Criteria Clarification 17

b. Appeals 19

VII. DIRECTORY FORMAT AND VERSION CONTROL 20

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES .....

IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES .....

APPENDIX A - DIRECTORY FORMAT TEMPLATE .....

APPENDIX B – NPCC REQUEST FOR CLARIFICATION .....

I. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and

translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC regional criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the References section of this manual.

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA.

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

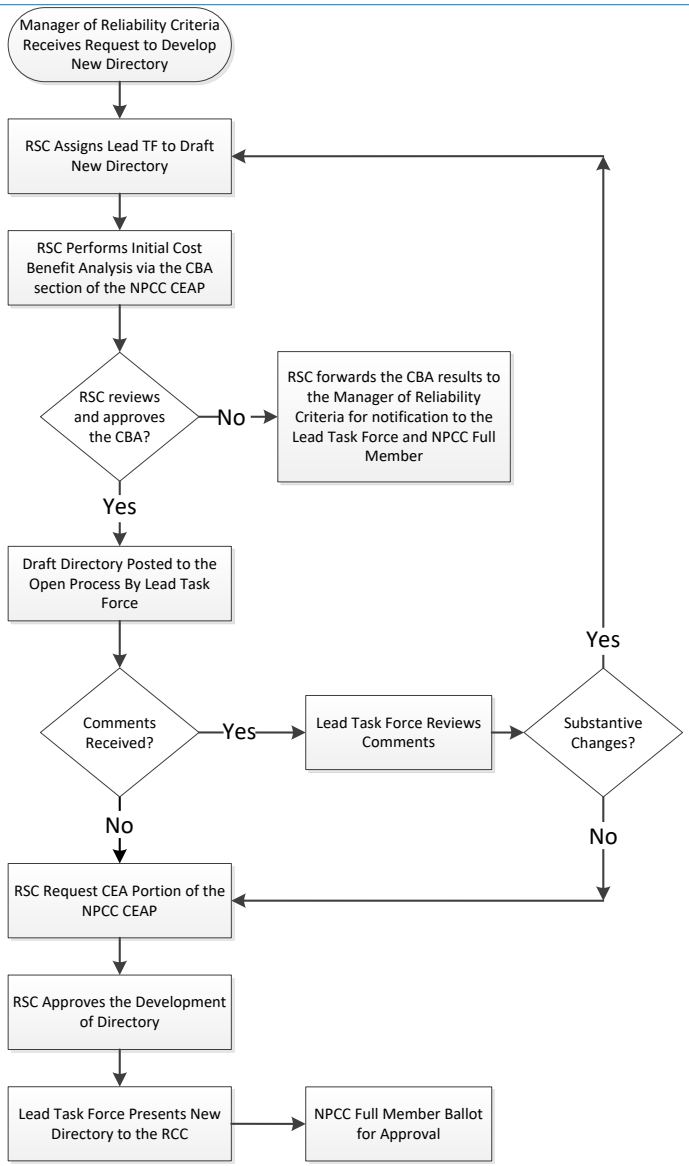
The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory.

After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

Figure 1: New Directory



Commented [GJD1]: Quintin….can you modify the Figure 1 to capture the additional language as per the comment received in the Open Process.

Commented [LQD2R1]: Replaced Figure 1

2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

Commented [LQD3]: Add' If requested by NPCC Manager of Reliability Criteria,'

In accordance with the CBA section of the CEAP if the RSC concludes that the revision to an existing Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

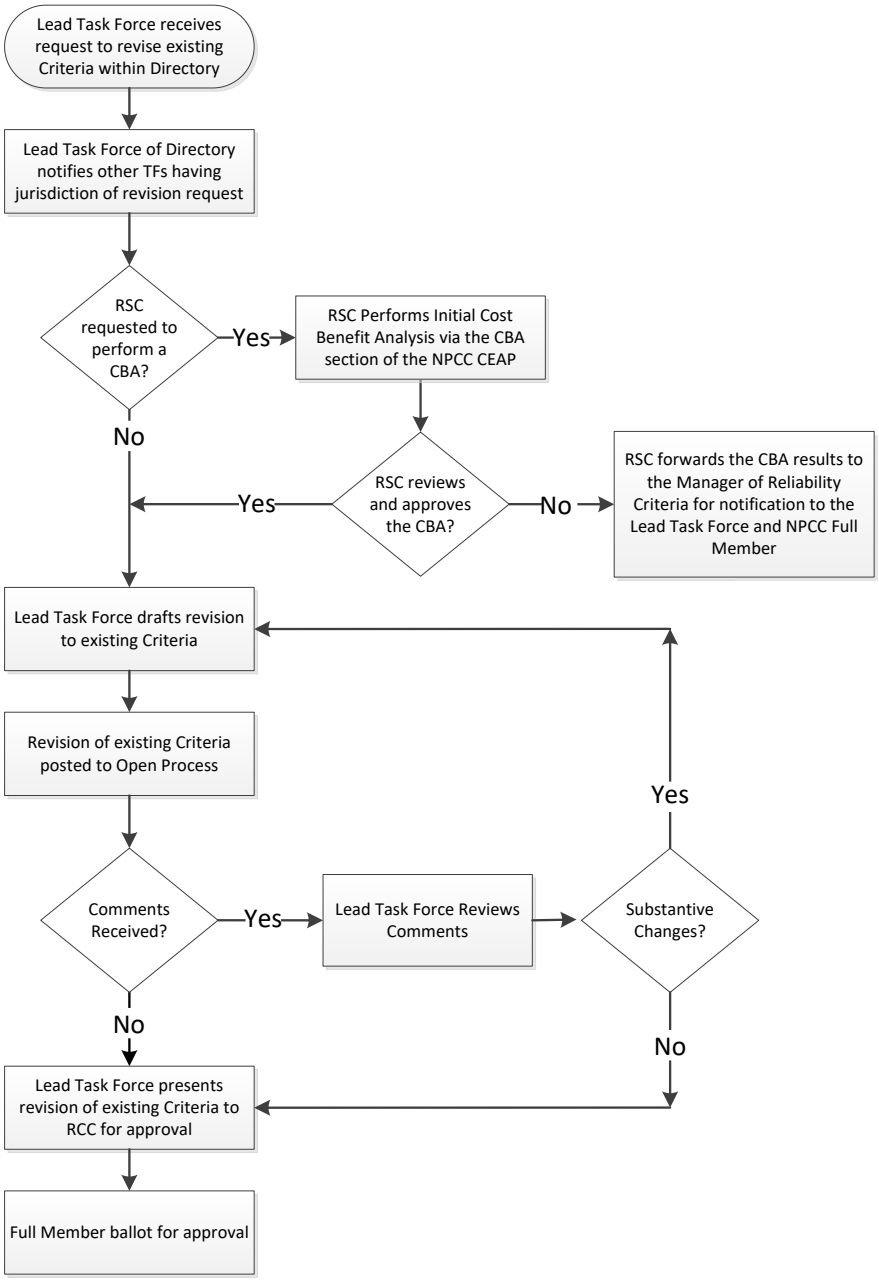
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



Commented [GJD4]: Quintin….can you modify the Figure 2 to capture the additional language as per the comment received in the Open Process.

Commented [LQD5R4]: Replaced Figure 2

b. Revisions to the Appendix Section of a Directory

Any NPCC Full Member may request an Appendix within a Directory to be revised, added or retired. Revisions, additions or retirements of Appendices shall only require Task Force approval.

A request to revise, add or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise, add or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received.

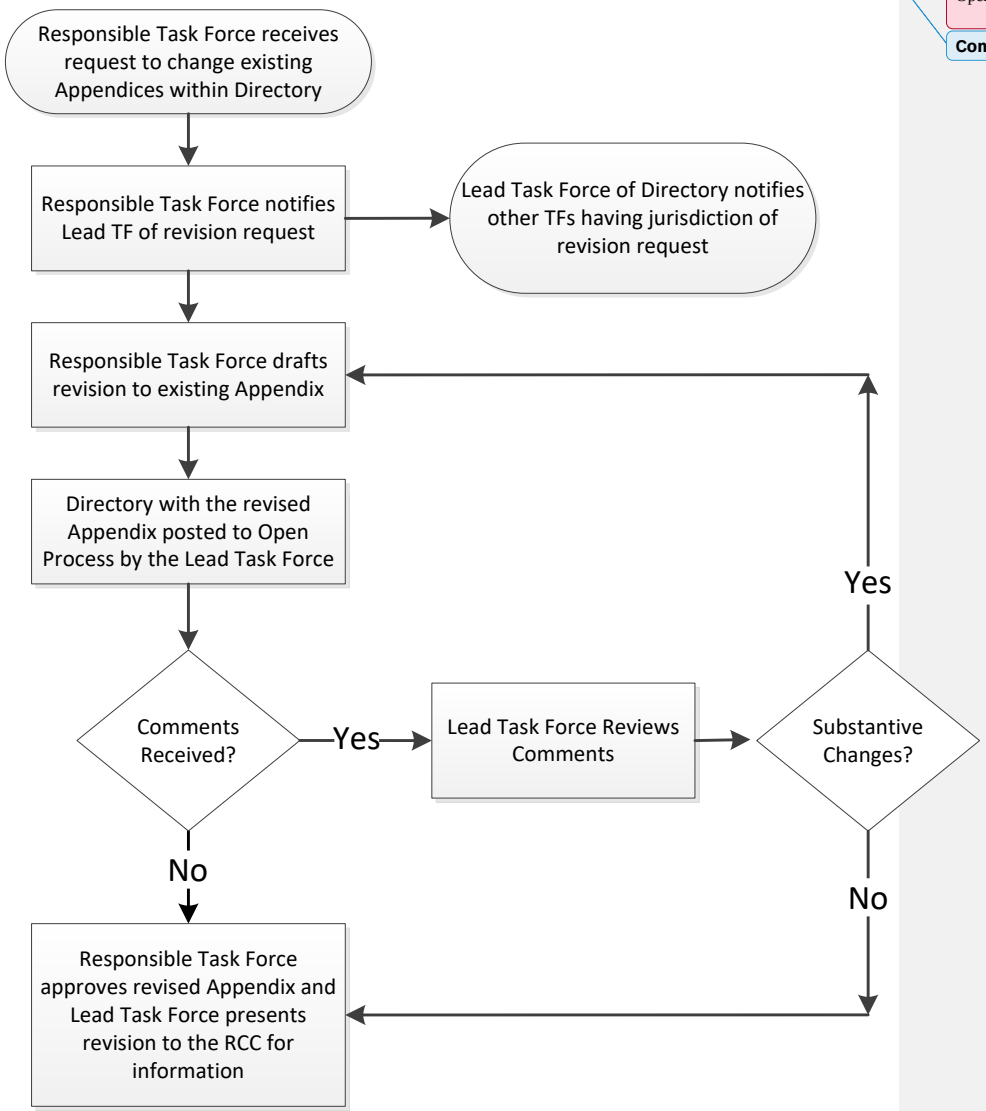
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the new, revised or retired Appendix. If the responses to the comments received on the new, revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the new, revised or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the new, revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the new, revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices



Commented [GJD6]: Quintin….can you modify the Figure 3 to capture the additional language as per the comment received in the Open Process.

Commented [LQD7R6]: Replaced Figure 3

c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new or revised Glossary term is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

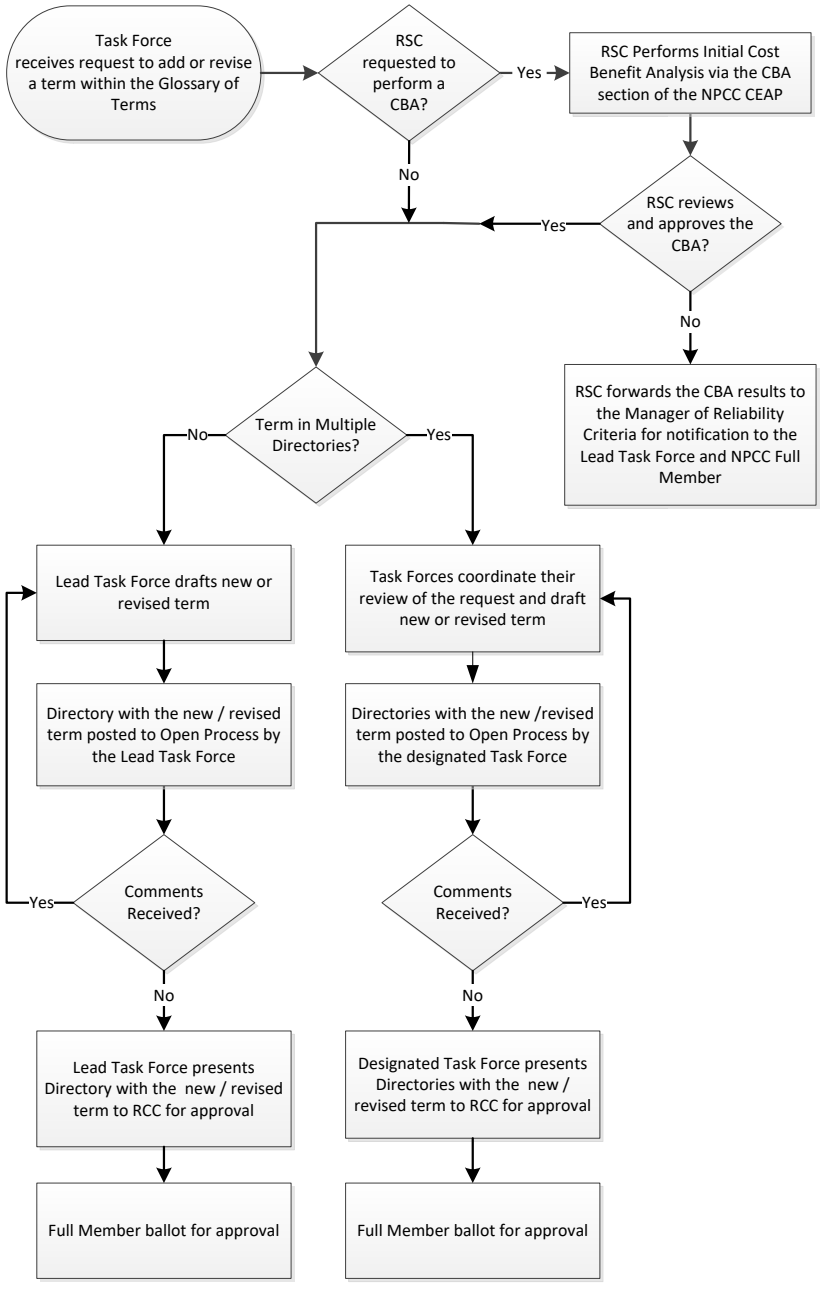
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



Commented [GJD8]: Quintin….can you modify the Figure 3 to capture the additional language as per the comment received in the Open Process.

Commented [LQD9R8]: Replaced Figure 4

d. Withdrawal Of Revision Requests

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. Directory Retirement

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

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. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. maintenance of Links and Errata

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory

[2] The Request for Clarification Form is included in Appendix B of this document.

clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

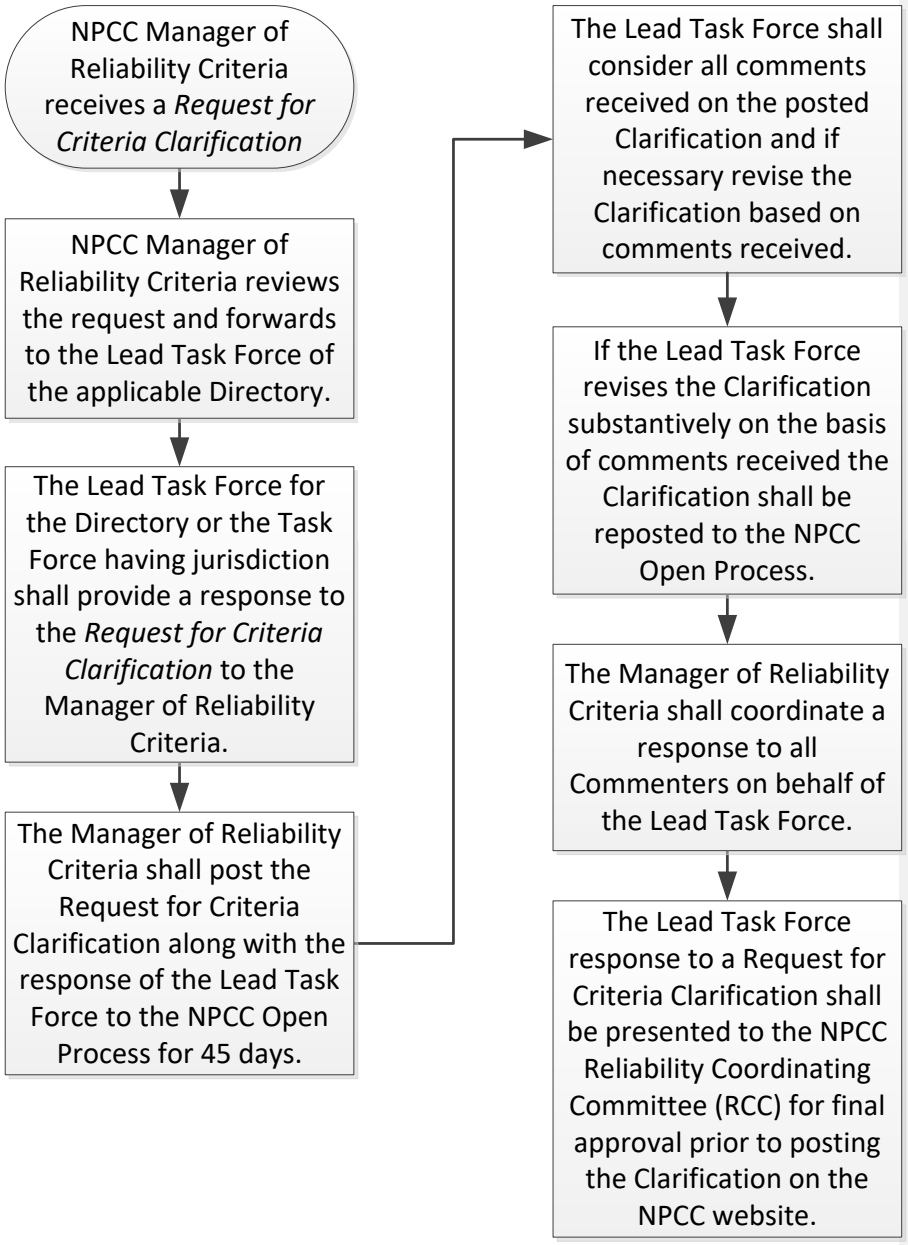
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document.

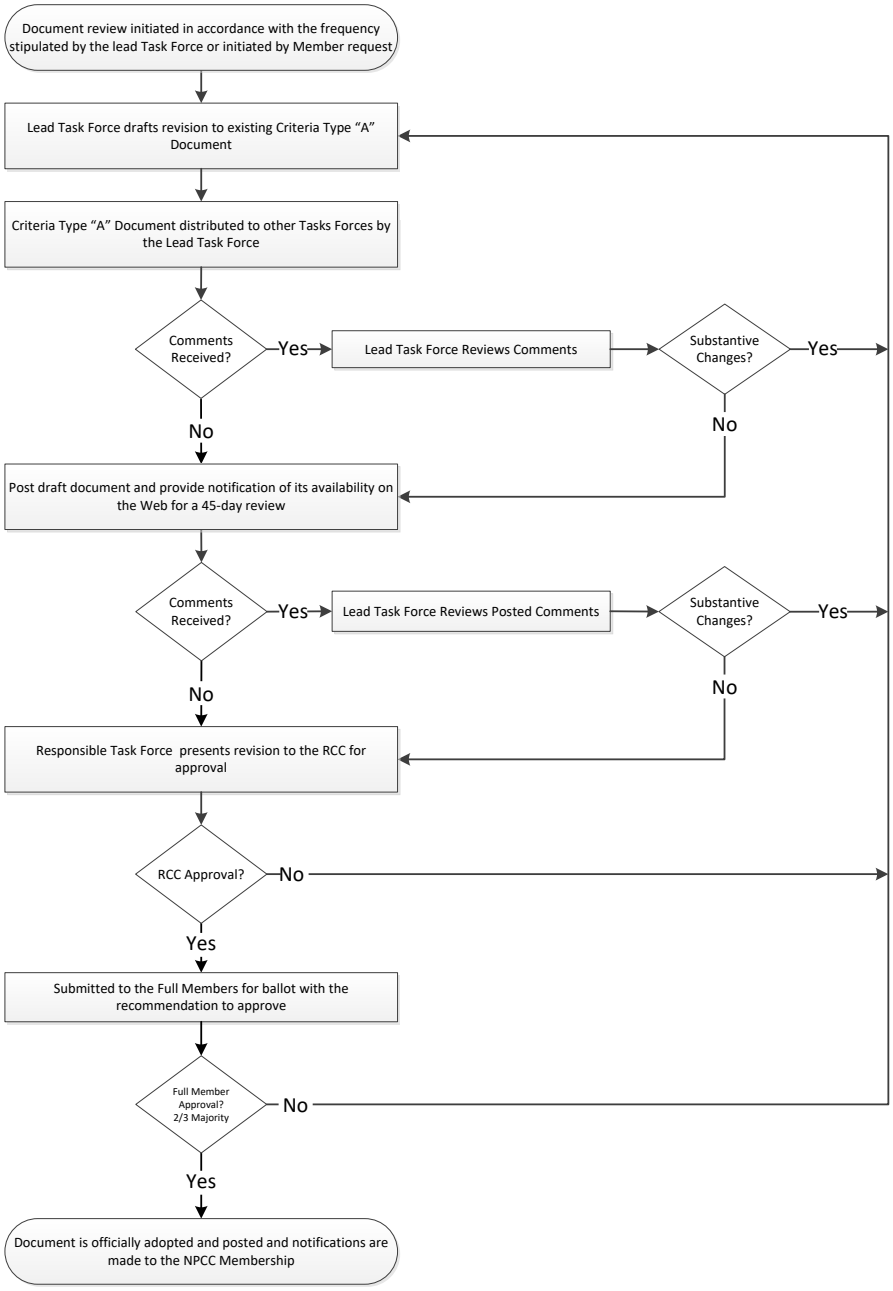
This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list.

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC “Appeals and Dispute Resolution Process” for non-compliance issues.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

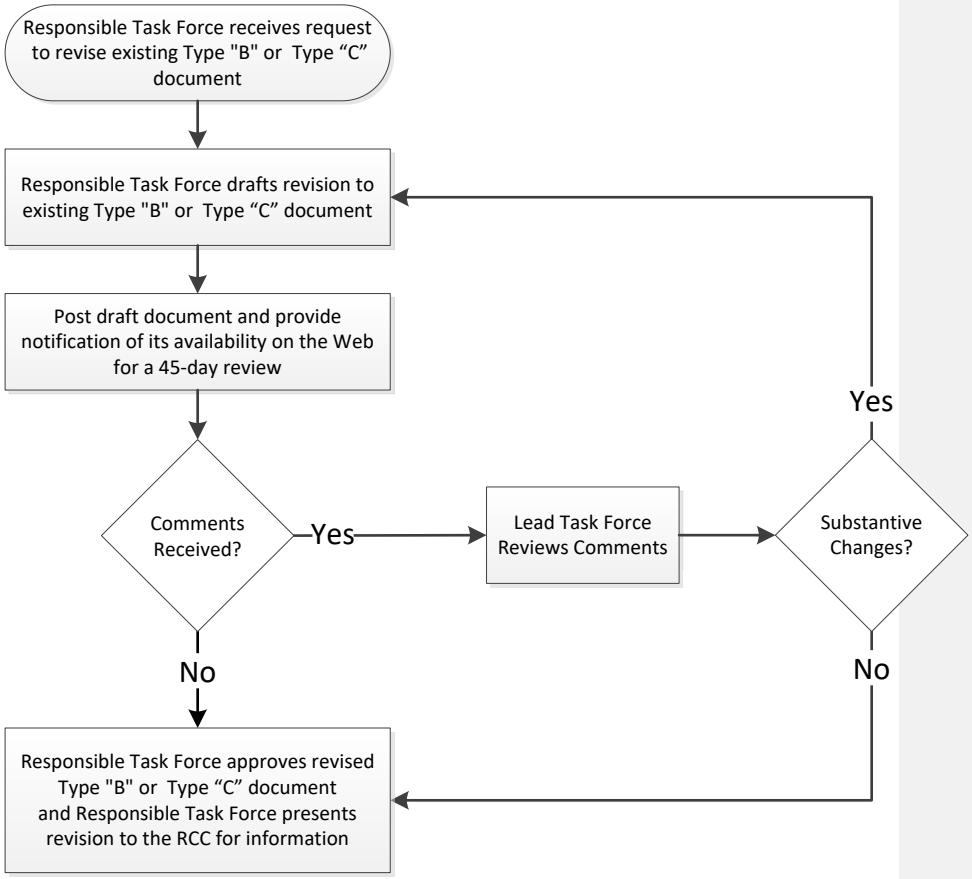
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to ~~the criteria in~~ an existing Type "B~~A~~" and “C”document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

APPENDIX A - DIRECTORY FORMAT TEMPLATE

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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

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

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

Document A-01

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

Content Transferred to NPCC Directory Development and Revision Manual

August 8, 2018

Criteria for Review and Approval of Documents

Task Force on Coordination of Planning Review Record:
March, 2005
April 21, 2017

Adopted by the Members of the Northeast Power Coordinating Council on October 28, 1986, based on recommendation by the Operating Procedure Coordinating Committee and the System Design Coordinating Committee in accordance with paragraph IV subheading (a), of NPCC's Memorandum of Agreement dated January 19, 1966 as amended to date.

Version History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	**March 1997**	**New**	
1	**March 2005**	**Revised**	
2	**April, 21st, 2017**	**Revised**	

Introduction

This Criteria is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all NPCC documents. NPCC documents have been divided into three categories, Document Type "A", Type "B" and Type "C". (See Appendix A for Process Flow Diagram and detailed description of process steps)

Document, Criteria-Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives, describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval. This final ballot approval will be conducted either at a scheduled RCC meeting or via email and electronic ballot.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for vote, with a recommendation for its adoption. Approval of an

NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.. See Appendix A for further details on the entire NPCC Open Process.

For new or modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list
Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for non-compliance issues.

Document, Guideline-Type "B"

General Description

Type "B" documents, with approval by the Reliability Coordinating Committee, are the guides or guidelines for the achievement of acceptable system performance which implement criteria of Type "A" documents.

Review and Approval

Type "B" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "B" document is presented by the lead Task Force to the Reliability Coordinating Committee for approval either at a scheduled RCC meeting or via email and electronic ballot. The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list. See Appendix A for further details on the entire NPCC Open Process.

Should the RCC determine that the document cannot be approved the RCC will return the document to the lead Task Force.

Members may request the lead Task Force, at any time, to review and revise the Guidelines, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.

Document, Procedure-Type "C"

General Description

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements of Type "A" and "B" documents.

Review and Approval

Type "C" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site.

The lead Task Force may invoke an expedited posting period for a "C" document if necessary to address implementation issues as identified by the lead Task Force.

Expedited postings will be for no less than 30 days.

The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required which would require an additional posting(s), the Type "C" document will be considered and voted on for final approval by the lead Task force and is then distributed for informational purposes to the Reliability Coordinating Committee and the other Task Forces. (Formal adoption by the Reliability Coordinating Committee or the NPCC Full Member Representatives is not required for Type "C" documents).

The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list with the next Reference Manual Revision. See Appendix A for further details on the entire NPCC Open Process.

The maintenance of Links, contact lists and the correction of errors found within NPCC documents ("A' Criteria, 'B' Guidelines and 'C' Procedures) shall be the responsibility of the NPCC Standards staff.

An error may be classified as Errata provided its correction does not change the scope or intent of the language.

Errata and Link revisions are updated as needed and require only the approval of the lead Task Force prior to publishing.

NPCC staff will also maintain a record of the change on the Record of Revision.

Members may request the lead Task Force, at any time, to review and revise the Procedures or References, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.

Lead Task Force: Task Force on Coordination of Planning

Reviewed for concurrence by: TFCO, TFSP, TFSS, CC, and TFIST

Review frequency: 4 years

Appendix A

NPCC OPEN PROCESS FOR REGIONAL RELIABILITY CRITERIA DEVELOPMENT AND REVIEW

Step 1 Initiation of the Open Process Review (Boxes 1, 2, 3, and 4) (Ref. A-01 Flowchart)

The NPCC Open Process for Regional Reliability Criteria Development and Review can be initiated a number of ways:

- A comment is submitted through the Open Process on the NPCC web site identifying an issue that could initiate a review. ***(Box 1)*** The Task Forces will review the comment and respond to it with a recommendation. ***(Box 2)***
- An NPCC Member, Task Force, CC, or other party may identify a reliability need that is currently not addressed in the existing set of documents. ***(Box 4)***

Once a NPCC Open Process for Review is initiated for a Document, it is identified and tracked in the NRAP Report. ***(Box 3)***

Step 2 Document Review and Revision (Boxes 5, and 6)

The designated lead Task Force as identified in the NRAP or as charged by the Reliability Coordinating Committee (RCC) to draft a new document will develop it and build a consensus within the Task Force. ***(Box 5)***

The document, once approved by the lead Task Force for public release, will be posted using the NPCC Open Process for a comment period. This comment period will begin once notification is made to the industry of the posting and comments will be accepted through the NPCC website for a period not to exceed 45 days. Notification will be given to neighboring Regions, whose reliability might be impacted by NPCC's Criteria, and their review of the proposed Criteria will be accommodated and submittal of their comments encouraged. ***(Box 6)***

Step 3 Industry Comments on the Posted Document (Boxes 7, 8, 9, 10, 11, 12, 14, 15, 17, and 18)

The industry and neighboring Regions whose Reliability may be affected have 45 days to submit their comments to the proposed document. ***(Box 7)***

At the end of the comment period the lead Task Force will review the comments and reach consensus on how to address the comments and decide whether

further revision to the document is necessary. ***(Box 8)*** Also as part of this revision the lead Task Force must ascertain if the revisions are substantive enough to require another posting.. ***(Box 11)***

The lead Task Force will then post the responses to the comments received to the NPCC Open Process for industry review. ***(Box 9)***

The document is revised as necessary into a "final" draft. ***(Box 10)***

If the document is a ***"C"*** (*a Procedure)* document, the document is voted on by the lead Task Force and if not approved further work is required and notification is posted. ***(Box 14, 15, 17 and 18)***

If the document is a ***"C"*** *(a Procedure)* document ***(Box 12)***, and approved by the lead Task Force, *go to Step 6* ***(Box 16)***

Step 4 Gaining other Task Force and RCC Approval (Documents "A" and "B" Type-Criteria or Guidelines only) (Boxes 12a 13, 19-25)

Following the posting of the Document, the affected Task Forces will arrange to review the document and approve it. ***(Boxes 12a and 13)***

If the document is not acceptable as is and further revision is requested the document will be returned to the lead Task Force with the specific recommended revisions. ***(Box 19)***

This revision, if accepted by the lead Task Force, may result in another Open Posting and notifications to neighboring Regions whose reliability might be impacted. ***(Box 20)***

If the NPCC Task Forces have all signified their acceptance and approval of the document, it will be forwarded to the RCC for its review. ***(Box 21)***

The RCC will vote on the document at its next scheduled meeting and if there are issues outstanding, the RCC will make specific recommendations to the lead Task Force and request that further work be done. Notification is posted. ***(Box 22, 23 and 24)***

If the document is approved by the RCC and is a ***"B" Type,*** (a *Guideline Document)****(Box 25)****, go to Step 6* ***(Box 26)***

Step 5 Gaining Full Member Representative Approval (Document "A" Type-Criteria only) (Boxes 27, 28, 31, and 32)

Upon approval of an "A Type" document by the RCC, the Document is submitted to the NPCC Full Member Representatives noting the recommendation by the RCC to approve. ***(Box 27)***

As outlined in the NPCC By-Laws approval of an NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.. ***(Box 28)***

If the document is not approved, any submitted comments by the Full Member Representatives will be forwarded along with the document back to the lead Task Force for further work and notification is posted. ***(Box 31 and 32)***

Step 6 Document is Officially Adopted (All Documents) (Boxes 16, 26, 29, 30, 33, 34, and 35)

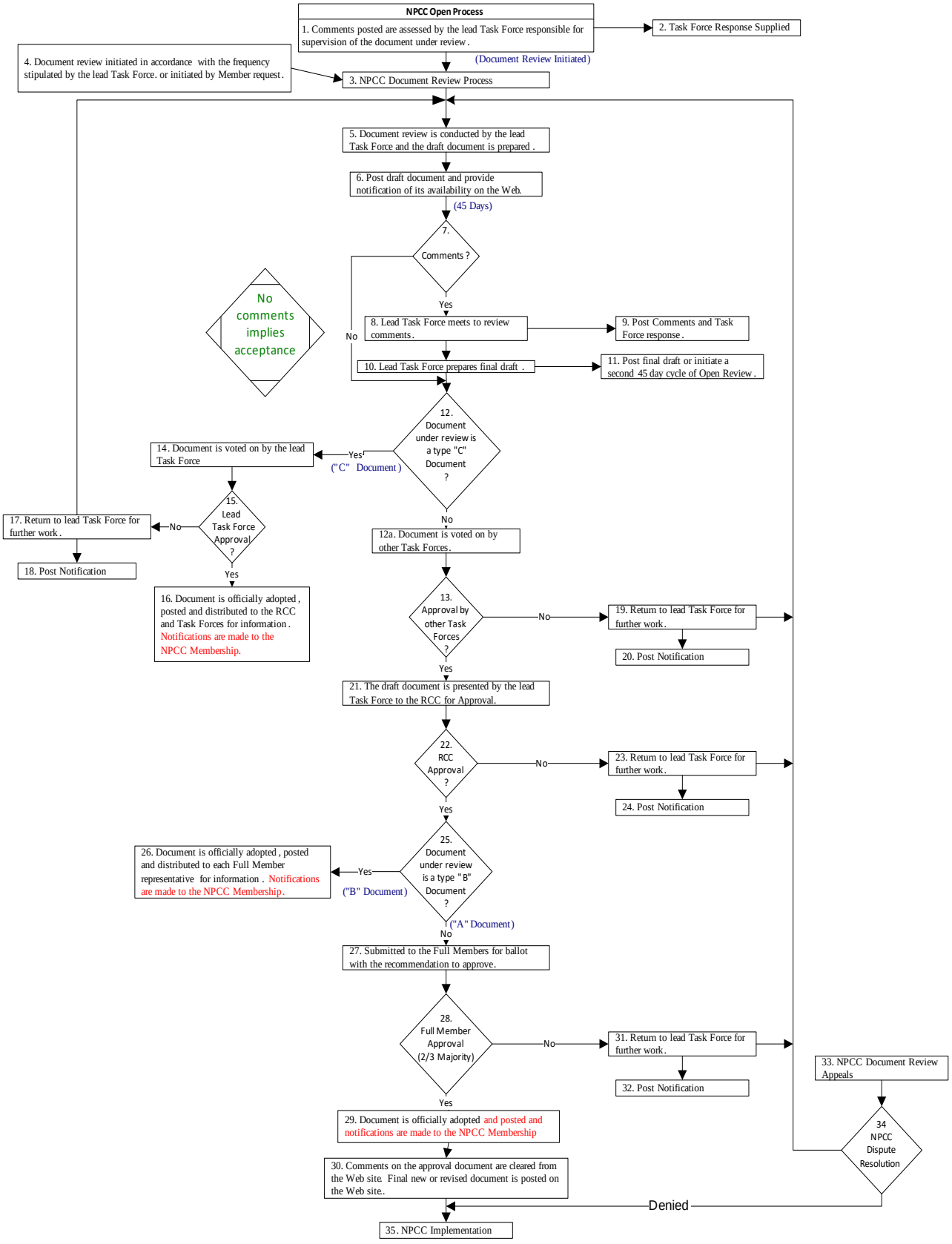
Document is officially adopted along with any implementation plan for compliance and notifications are made to the NPCC Membership. ***(Boxes 16, 26, and 29)***

Document is posted on the public portion of the NPCC website, replacing the old document if a revision is made. NPCC Staff will also update the NRAP as required to show the next scheduled review date. ***(Box 30)***

The requirements and procedures in the revised or new document are implemented, as stated in the implementation plan, or continued as required by the document. ***(Box 35)***

At anytime during the process and prior to implementation the document is subject to the NPCC Dispute Resolution Process. ***(Box 33 and 34)***

NPCC Open Process of
Criteria, Guidelines and Procedures



NORTHEAST POWER COORDINATING COUNCIL, INC.
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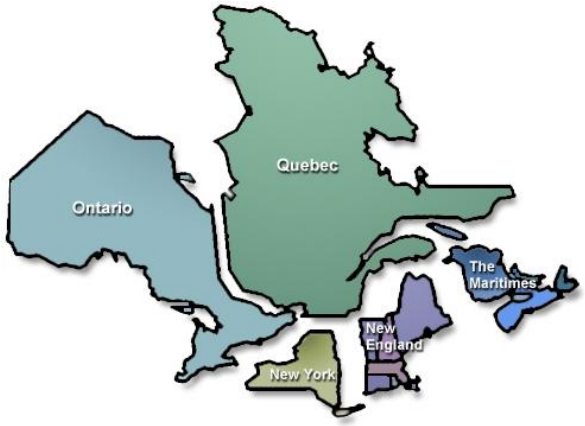
Redlined
Open Process Comments Considered

July 25, 20218

Northeast Power Coordinating Council, Inc. Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines, and Procedures



Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL
& PROCESS FOR THE REVIEW and APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

Table of Contents

I. EXECUTIVE SUMMARY 2

II. BACKGROUND 2

III. APPLICABILITY OF NPCC CRITERIA 4

IV. TASK FORCE ROLES AND RESPONSIBILITIES 4

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 5

1. NEW DIRECTORY 5

2. DIRECTORY REVISIONS 7

a. Revisions to the Criteria Section of a Directory 7
b. Revisions to the Appendix Section of a Directory 10
c. Revisions To The NPCC Glossary Of Terms 12
d. Withdrawal Of Revision Requests 15

3. DIRECTORY RETIREMENT 15

4. MAINTENANCE OF LINKS AND ERRATA 15

VI. DIRECTORY CLARIFICATION PROCESS 16

a. Request for Criteria Clarification 16
b. Appeals 19

VII. DIRECTORY FORMAT AND VERSION CONTROL 19

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES .....

IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES .....

APPENDIX A - DIRECTORY FORMAT TEMPLATE .....

APPENDIX B – NPCC REQUEST FOR CLARIFICATION .....

I. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and

translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC regional criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the References section of this manual.

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA.

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory. After the RCC approves both the draft Directory and the CEAP the draft Directory is

submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

Figure 1: New Directory

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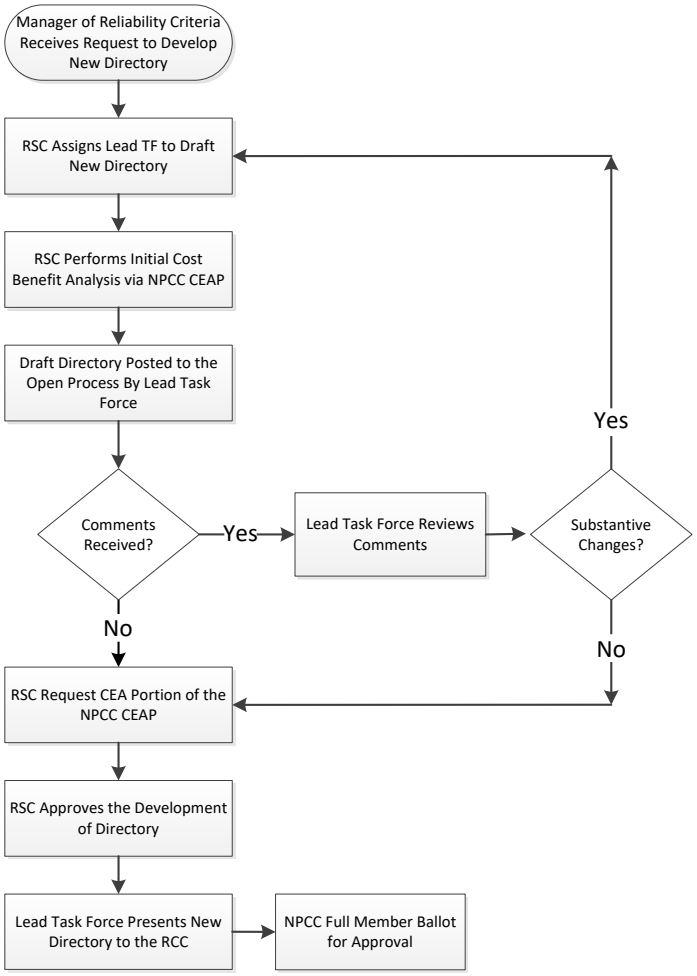


[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

In accordance with the CBA section of the CEAP if the RSC concludes that the revision to an existing Directory is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

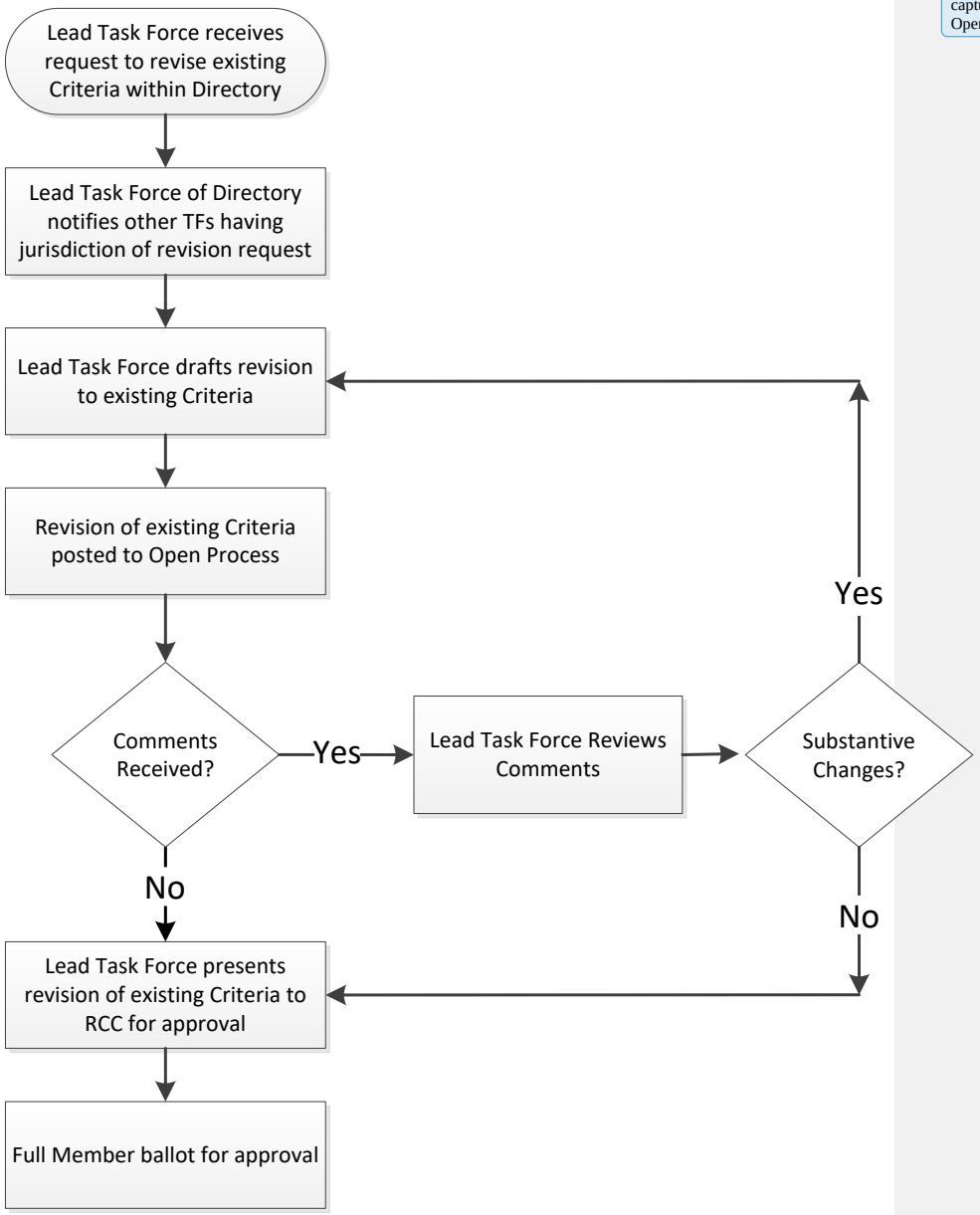
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



Commented [GJD2]: Quintin….can you modify the Figure 2 to capture the additional language as per the comment received in the Open Process.

b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised, added or retired. Revisions, additions or retirements of Appendices shall only require Task Force approval.

A request to revise, add or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise, add or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received.

After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the new, revised or retired Appendix. If the responses to the comments received on the new, revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the new, revised or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the new, revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the new, revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices

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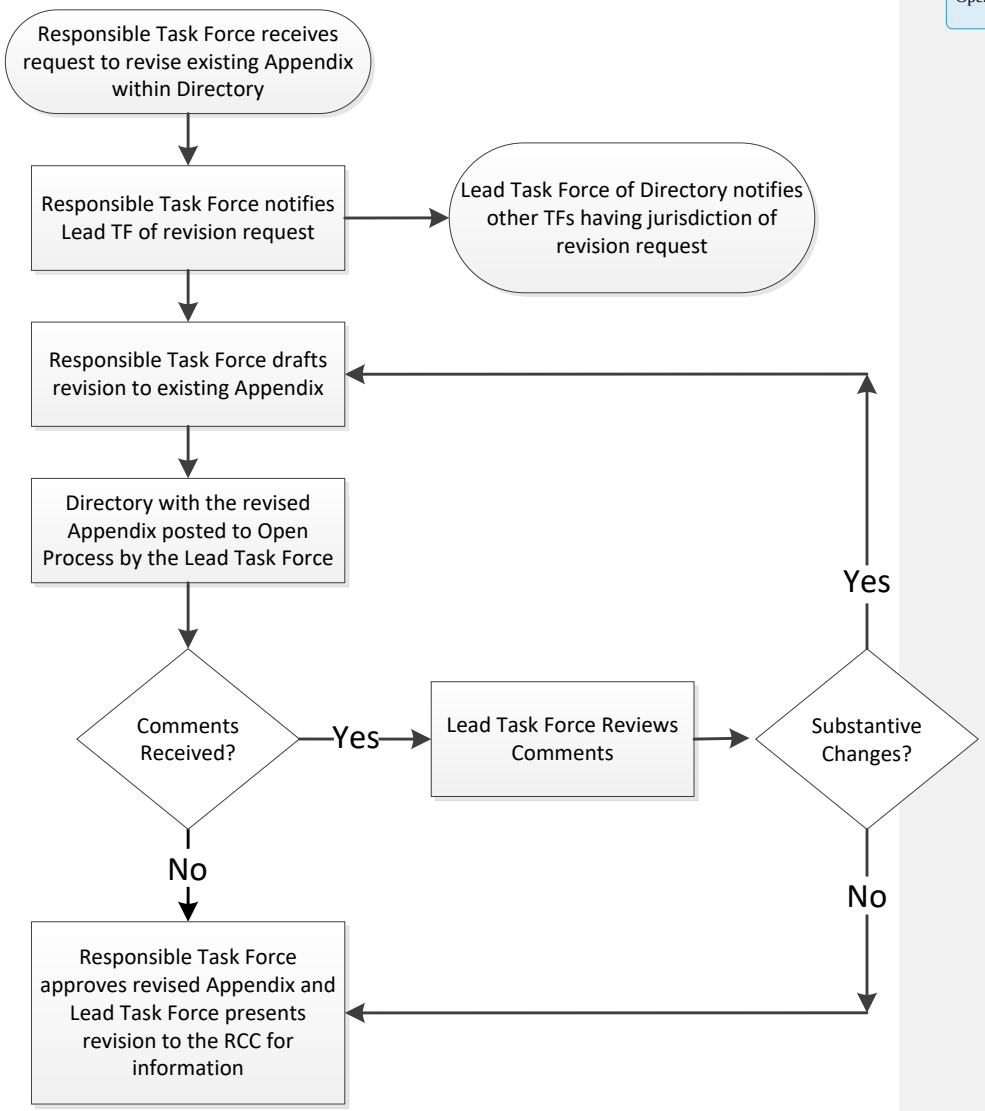


c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new or revised Glossary term is not warranted the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

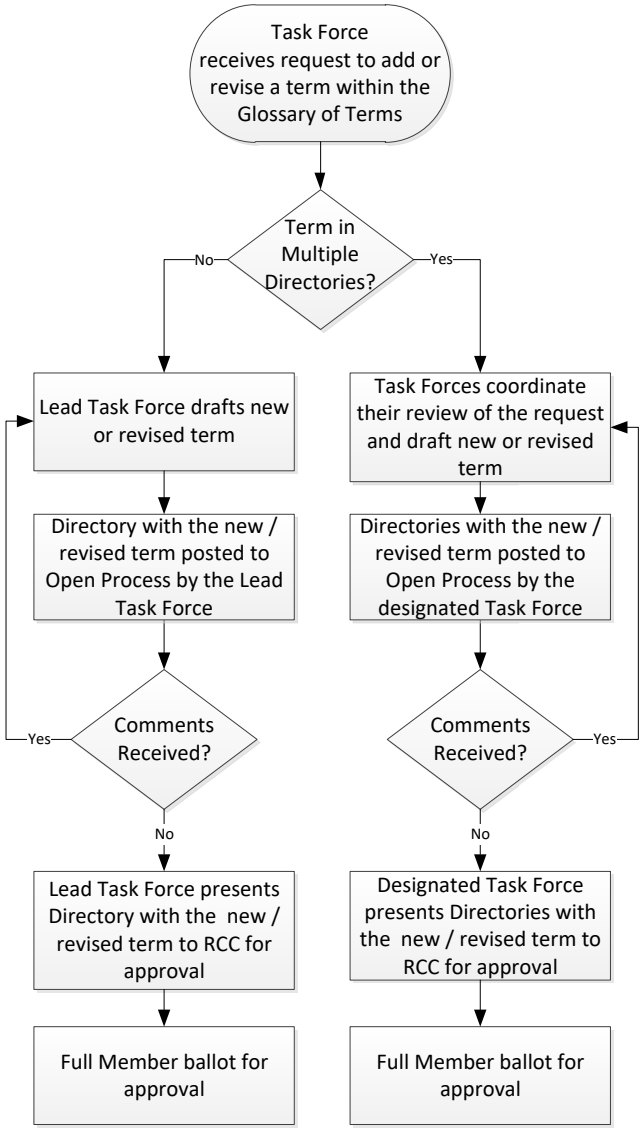
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



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d. Withdrawal Of Revision Requests

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. Directory Retirement

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

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. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. maintenance of Links and Errata

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory

[2] The Request for Clarification Form is included in Appendix B of this document.

clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

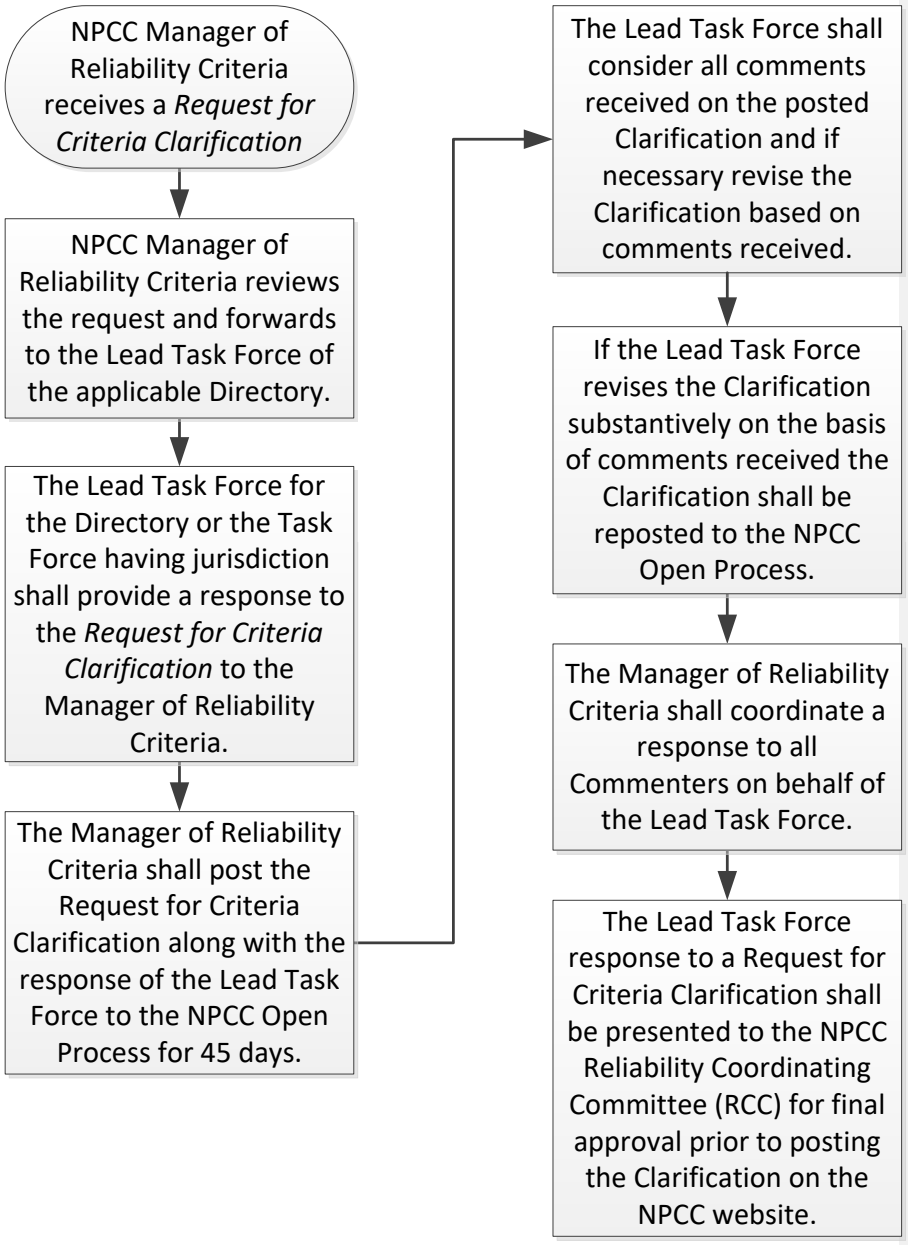
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document.

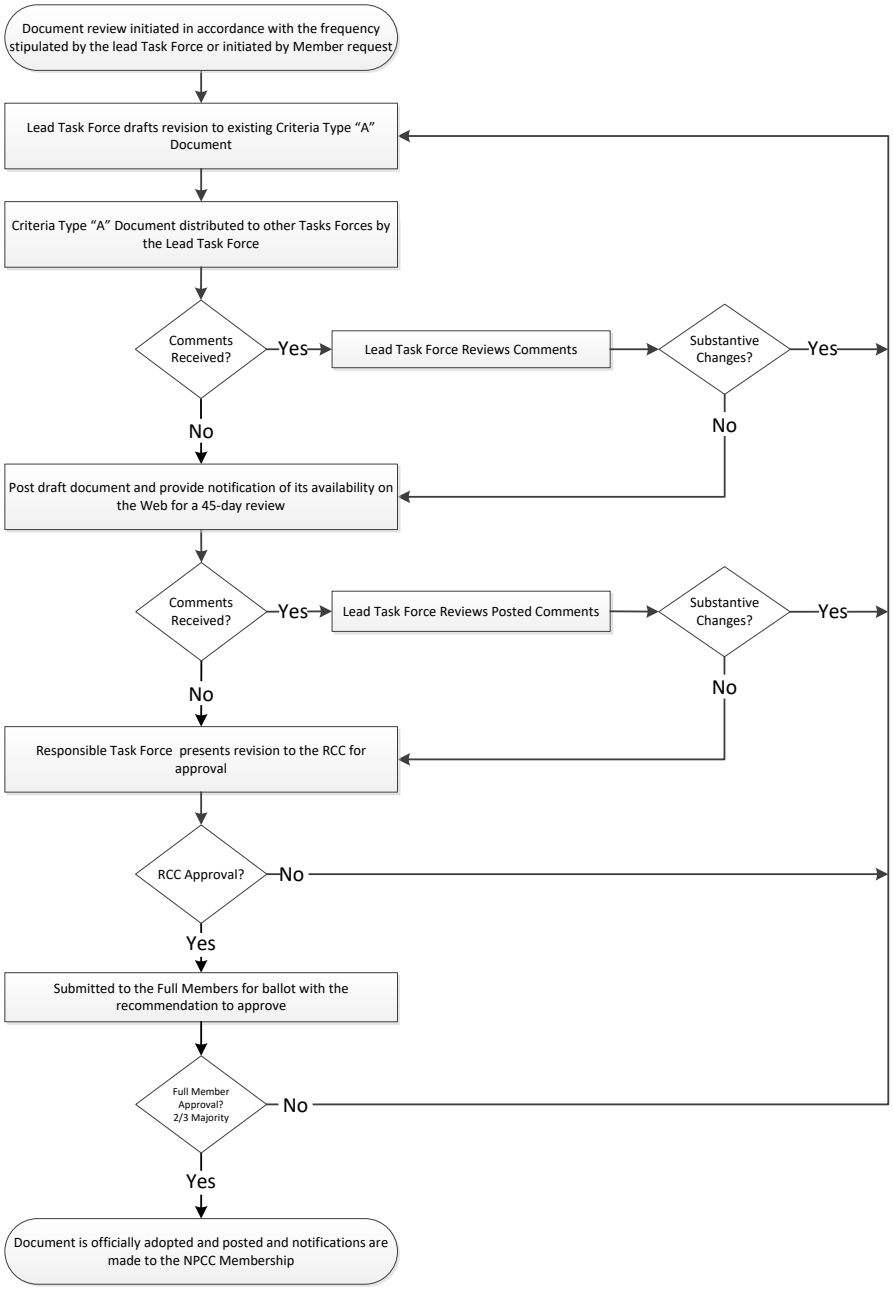
This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list.

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC “Appeals and Dispute Resolution Process” for non-compliance issues.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

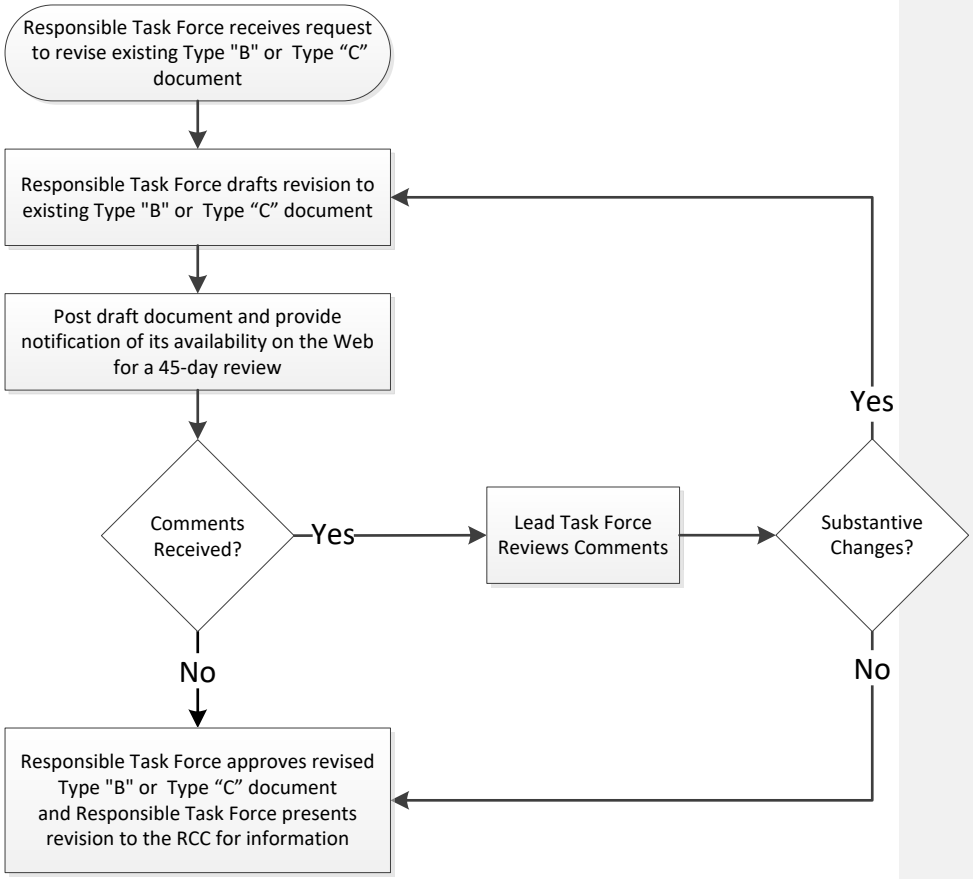
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to ~~the criteria in~~ an existing Type "B~~A~~" and “C”document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

APPENDIX A - DIRECTORY FORMAT TEMPLATE

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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

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

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

August XX, 2018

Draft RSC Responses

Open Process Comments

August 9, 2018

The Regional Standards Committee (RSC) Response to Comments Received in the Open Process Posting of the NPCC *Directory Development and Revision Manual*.

The RSC would like to thank those who provided comments on the proposed revisions to the Directory Manual posted from April 25, 2018 through June 9, 2018.

RSC responses to individual comments are provided below.

Comments from the IESO:

The IESO respectfully submits the following comments on the subject draft document for consideration by the lead task force responsible for drafting this document.

IESO Comment #1:

Cost Benefit Analysis (CBA) for New Directory:

The IESO supports an initial CBA for proposals to develop new Directories. However, Section V.1. is silent on the situation where the CBA results should indicate that it is not cost beneficial to develop the proposed directory. We suggest to add a few words to address this possibility, along with an additional flow path in Figure 1.

RSC Response:

Comment accepted.

Section V of the Manual revised to consider the possibility that the Cost Benefit Analysis (CBA) section of the NPCC Cost Effectiveness Analysis Procedure (CEAP) determines that a new Directory is not warranted.

The corresponding figure (Figure #1) has also been revised.

IESO Comment #2:

Cost Benefit Analysis (CBA) for Revised Directory:

The above comments also apply to proposals for revising existing Directories in the event that the NPCC Manager of Reliability Criteria requests the RSC to perform an initial analysis of the cost benefit of the proposed Directory revision.

In addition, we suggest the process for NPCC Manager of Reliability Criteria requesting the RSC to perform an initial analysis of the cost benefit of the proposed Directory revision be reflected in the flow chart (Figure 2).

RSC response:

Comment accepted.

Section V of the Manual revised to consider the possibility that the Cost Benefit Analysis (CBA) section of the NPCC Cost Effectiveness Analysis Procedure (CEAP) determines that a revision to an existing Directory is not warranted.

The corresponding figure (Figure #2) has also been revised.

IESO Comment #3:

Proposal to Add an Appendix Section:

Section V 2b presents the process for revising or retiring an existing Appendix Section. There is no discussion on the process to add a new Appendix Section in those cases where the NPCC Manager of Reliability Criteria requests the RSC to perform an initial analysis of the cost benefit of the proposed Directory revision.

We propose this Section and the process diagram in Figure 3 be expanded to also present the process for adding a new Appendix Section.

RSC response:

Comment accepted.

Section V 2b of the Manual revised to consider the circumstances surrounding a request for a new Appendix.

However, an Appendix is a supporting document that supports the achievement of system performance related to the criteria and the addition of an Appendix should not result in significant cost implications.

Therefore, this Section does not contain a requirement to consider a Cost Benefit Analysis.

IESO Comment #4:

Revision to the NPCC Glossary of Terms:

The comments on CBA in (2) above also applies to this Section (V. 2c) for cases where the NPCC Manager of Reliability Criteria requests the RSC to perform an initial analysis of the cost benefit of the proposed or revised Glossary term.

RSC response:

Comment accepted.

Section V 2c of the Manual revised to consider the possibility that the Cost Benefit Analysis (CBA) section of the NPCC Cost Effectiveness Analysis Procedure (CEAP) determines that the development of a new or revised Glossary term is not required.

The corresponding figure (Figure #4) has also been revised.

Comments from Consolidated Edison

Con Ed Comment #1:

On the bottom of page 22 in the combined "Clean/Redline" version of the document, in the B & C guideline section reads: "The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 7" but should describe B & C documents instead.

RSC response:

Comment accepted.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)** **)**	**Docket No. RM13-11-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The North American Electric Reliability Corporation ("NERC") hereby submits this informational filing ("Informational Filing") to the Federal Energy Regulatory Commission ("Commission") as directed in Order No. 794.[1] In Order No. 794, the Commission approved Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) and directed NERC to submit an informational filing after implementation of the standard, "addressing: (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."[2] As discussed in this Informational Filing and detailed in the attached *Technical Report on NERC Standard BAL-003-1.1* ("Report"), the record demonstrates that: (1) the median method of calculating the Frequency Response Measure ("FRM") continues to provide more accurate results than the linear regression method; and (2) that sufficient frequency response resources existed in 2017 for applicable entities to meet their Frequency Response Obligation ("FRO").

In addition, data indicates that Reliability Standard BAL-003-1.1 has improved reliability by supporting recovery from frequency deviations. The Report summarizes lessons learned and

[1] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

[2] *Id.* at P 3. Prior filings in compliance with other directives in Order No. 794 have been submitted in the above captioned docket.

opportunities for enhancement being examined by the Standard Drafting Team ("SDT") developing modifications to Reliability Standard BAL-003-1.1 and by NERC technical committees. Together with industry, NERC will continue examining frequency response and potential modifications to Reliability Standards, as appropriate. NERC submits this Informational Filing in compliance with all remaining directives related to Order No. 794.

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this filing may be addressed to the following:[3]

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[3] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2018), to allow the inclusion of more than two persons on the service list in this proceeding.

II. COMMENTS

A. The Median Method of Calculating the FRM

In Order No. 794, the Commission stated that:

> [T]he Commission acknowledges NERC's commitment to studying the use of linear regression and the analysis contained in the Frequency Response Initiative Report, and directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission …. The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure.[4]

As detailed in the attached Report, data demonstrates that the median method of calculating the FRM continues to provide more accurate results than the linear regression method. To complete its statistical analysis, NERC compared the Interconnection Frequency Response Performance Measure ("IFRM") for each BAL-003-1.1 frequency event in the 2017 operating year,[5] against aggregate performance for all Balancing Authorities ("BAs") in the Interconnection for the same event as calculated under (1) the median method; and (2) the linear regression method. Under this statistical analysis, the method producing the outcome closest to 1.0 compared to the IFRM was considered to provide a better quality measurement.[6] NERC ran this comparison of the IFRM to aggregated BA FRMs as calculated under the median and linear regression methods for the Eastern, Western, and Texas Interconnections. For each Interconnection evaluated, the median method led to results closest to 1.0. Thus, NERC determined that the median method is the most accurate means of calculating the FRM under the current standard.

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[4] Order No. 794 at P 34.

[5] The first operating year that Requirement R1 was effective.

[6] The IFRM was used to benchmark accuracy of BA FRMs in this manner, because the IFRM is considered the most accurate calculation of frequency response performance in an Interconnection for any single BAL-003-1.1 frequency event as the IFRM does not include variables such as tie line error.

B. Adequacy of Frequency Response Resources in the First Year of Implementation of the Standard

In Order No. 794, the Commission:

> [D]irect[ed] NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation…. The required report should provide data indicating whether actual frequency response was sufficient to meet each balancing authority's Frequency Response Obligation.[7]

NERC has determined that adequate frequency response resources existed in 2017 for each BA to meet the FRO.[8] NERC reached this conclusion after evaluating the 2017 operating year results for Interconnections in the U.S. In the Texas Interconnection, the BA's FRM performance exceeded the FRO. For the Eastern and Western Interconnections, NERC evaluated BA frequency event data submitted for the 2017 operating year to assess whether a BA's percentage of total Interconnection generation was less than their percentage of the total IFRO. In the Western Interconnection, none of the 38 BA's FRM performance failed to meet the FRO.[9] In the Eastern Interconnection, 32 out of the 34 BAs had FRM performance satisfying the FRO. Only two BAs failed to have FRM performance meeting the FRO. These two BAs appear to have been outliers, however, as they were small BAs with combined FROs of less than 0.1% of the total IFRO of the Interconnection and did not use transferred frequency response to help meet their obligation. NERC will continue monitoring this issue.

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[7] Order No. 794 at P 60.

[8] Operating year 2017 was the first year of implementation for Requirement R1 of Reliability Standard BAL-003-1.1.

[9] Out of this group, 11 transferred frequency response from another BA during at least one event to support compliance with the standard.

C. The Report Summarizes Efforts to Further Address Issues Related to Frequency Response

As detailed in the Report, NERC is building on Reliability Standard BAL-003-1.1 to further address issues related to Frequency Response. The SDT for NERC Standards Project 2017-01 is evaluating potential modifications of NERC Reliability Standards in light of lessons learned under Reliability Standard BAL-003-1.1, the changing resource mix, inverter based resource penetration, altered dispatch patterns, and issues surrounding resource availability versus capability. Revisions to NERC Reliability Standards are being pursued over two phases to support continued progress towards enhanced reliability. Subject to completion of the standards development process and NERC Board of Trustees approval, NERC plans to submit the initial phase of modifications to Reliability Standard BAL-003-1.1 in 2019. In addition to SDT work, NERC will continue to coordinate with and rely on technical committee analysis of matters related to Frequency Response. The Resources Subcommittee of the Operating Committee, for example, has taken an active role over the past four years supporting NERC's implementation of the standard and its evaluation of frequency response matters.

III. CONCLUSION

Wherefore, as detailed in the Report, NERC's analysis demonstrates that: (1) the median method for calculating the FRM continues to provide more accurate results than the linear regression method; and 2) sufficient resources were available in operating year 2017 to support applicable entity FROs. NERC is continuing to build on the progress made in Reliability Standard BAL-003-1.1 through two phases of revisions to the standard and strong industry coordination. NERC submits this informational filing as compliant with the Commission's remaining directives in Order No. 794.

Respectfully submitted,

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Date: June 29, 2018

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 29th day of June 2018.

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Attachment

Technical Report on NERC Standard BAL-003-1.1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Report on NERC Standard BAL-003-1.1

Informational Filing in Compliance with FERC Order 794

June 29, 2018

RELIABILITY | ACCOUNTABILITY

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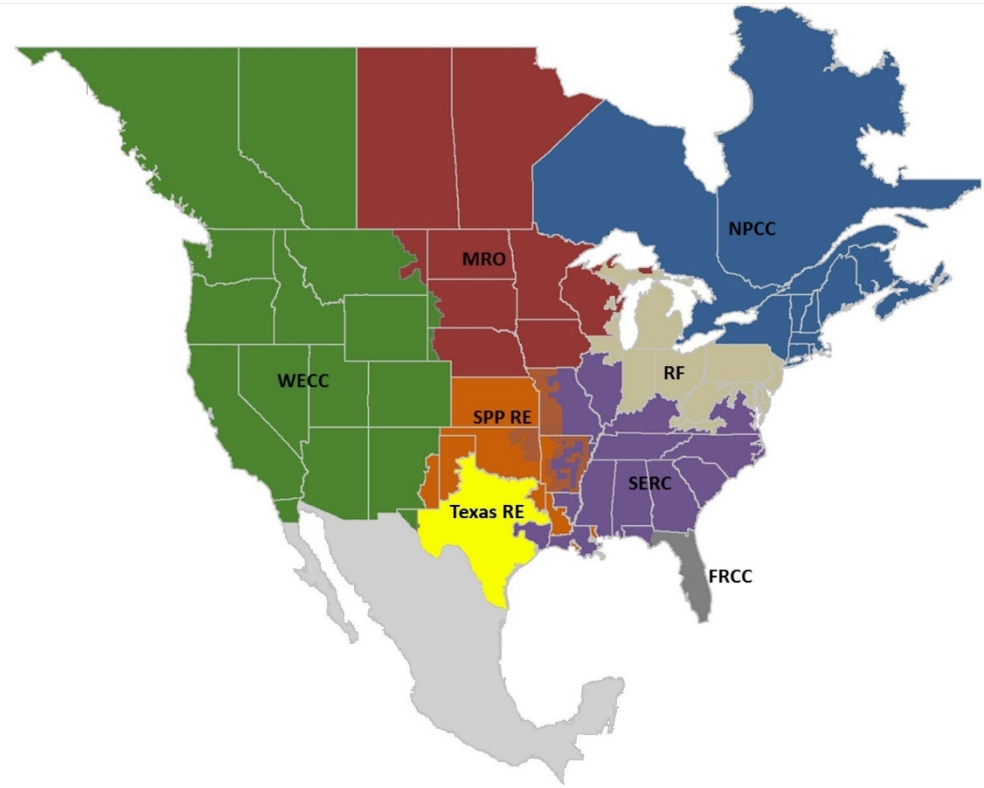
Table of Contents

Preface iii
Executive Summary iv
Response to Order No. 794 Directives iv
Introduction v
Chapter 1: Order 794 Directives 1
Analysis of Regression versus Median Statistical Method 1
Availability of Frequency Response Resources 2
Chapter 2: BAL-003-1.1 Standard Authorization Requests 4
Appendix A: Supporting Data 5

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into eight RE boundaries as shown in the map and corresponding table below. 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

In Order No. 794, the Federal Energy Regulatory Commission (FERC or Commission) approved *Reliability Standard BAL-003-1* and issued certain directives for an informational filing describing the results of implementation of the standard.[1] In the Order, the Commission directed NERC to do the following:

> "…submit a report(s) addressing: (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." [2]

NERC is submitting this report to satisfy those directives and prepared it by using frequency response performance data submitted by Balancing Authorities (BAs) in the Eastern Interconnection (EI), Western Interconnection (WI), and Texas Interconnection (TI) for the 2017 operating year[3] in accordance with BAL-003-1.1 Key findings and recommendations from the analysis described below are examined in this report and summarized in this executive summary.

Response to Order No. 794 Directives

The following are the findings and recommendations pertaining to directives of FERC Order No. 794:

1. **Evaluation of the Use of the Linear Regression Method to Calculate Frequency Response:** The median provided a better quality of measure of BA frequency response measure (FRM) performance as benchmarked against the Interconnection frequency response measure (IFRM) for events in the 2017 operating year. NERC recommends that Reliability Standard BAL-003-1.1 should continue to use the median method to measure annual BA FRM performance under the current construct of the standard.
2. **Evaluation of the Availability of Resources for Applicable Entities to Meet the Frequency Response Obligation:** NERC concludes that an adequate availability of frequency responsive resources existed in the 2017 operating year for each BA to meet their frequency response obligation (FRO).

This report also discusses work being done through Standards and Stakeholder Committee activities in support of Frequency Response.

[1] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶61,024 (2014).
[2] Order No. 794, p. 3.
[3] December 1, 2016 through November 30, 2017

Introduction

Frequency support is recognized as an essential reliability service. NERC *Reliability Standard BAL-003-1.1*[4] is intended to require sufficient frequency response from the BAs to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. Reliability Standard BAL-003-1.1 is intended to provide consistent methods for measuring frequency response and determining the frequency bias settings. The standard applies to all BAs or the FRSG, if the BA is a member of an FRSG.

NERC, in coordination with the REs, has established a target contingency protection criterion for each Interconnection called the IFRO. NERC manages the administrative procedure for annually assigning an FRO to each BA based on the allocation formula below that considers load and generation of the BA in relation to the Interconnection. All BAs in an Interconnection are allocated an FRO and are required to meet their obligation. This includes load-only and generation-only BAs regardless of size. In the event that a BA does not have resources within their footprint to meet their FRO, they may acquire frequency response from entities outside of their balancing area. This is also true of generation-only BAs when their resources may be off-line during BAL-003-1.1 frequency events. Load and generation data used to calculate FRO is sourced from the most recent FERC Form 714s filed by BAs, or from similar data requested by NERC when the BA is non-FERC jurisdictional.

$$FRO_{BA} = IFRO\ x\ \frac{Annual\ Gen_{BA} + Annual\ Load_{BA}}{Annual\ Gen_{Int} + Annual\ Load_{Int}}$$

Specifically, BAL-003-1.1 Requirement 1 reflects the connection between FROs and BA obligations and states:

> "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient frequency response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation."

Each BA calculates its FRM from single-event frequency response data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The ERO selects events in FRS Form 1 by using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.*[5] The FRS forms for each Interconnection are posted on the NERC Balancing Authority Submittal Site (BASS). The BASS is a secure website where BA users are vetted by NERC and granted access to obtain BAL-003-1.1 forms and information and to submit their annual performance results in accordance with the standard. NERC validates the submitted data that is also used to calculate annual frequency bias settings (FBS). The SEFRD for a typical BA in an Interconnection with more than one BA is basically the change in its net actual interchange on its tie lines with its adjacent BAs divided by the change in Interconnection frequency.[6] Assuming data entry is correct, FRS Form 1 is intended to automatically calculate the BA's FRM for the operating year as the median of the SEFRD values.

[4] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

[5] https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/Procedure_Clean_20121130.pdf

[6] Certain adjustments to the SEFRD calculation are allowed and are incorporated into the FRS Form 1 and 2 functionality. They include adjustments for Contingent BA, Non-Conforming Loads, Pumped Hydro, Dynamic Schedules, and Transferred Frequency Response between BAs. All events listed on FRS Form 1 must be included in the annual submission of FRS Forms 1 and 2.

Chapter 1: Order 794 Directives

Analysis of Regression versus Median Statistical Method

The Commission directed NERC to "assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure."[7] As stated in the Order:

> "… the Commission acknowledges NERC's commitment to studying the use of linear regression and the analysis contained in the Frequency Response Initiative Report, and directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure.[8]"

This report documents NERC's evaluation of the median versus regression method to determine BA FRMs based on the data collected following the implementation of BAL-003-1.1. Based on its analysis, NERC concludes that the median method provides a better quality of measure of BA FRM performance than linear regression. BAL-003-1.1 should continue to use the median to measure annual BA FRM performance under the current construct of the standard.

The median method provided a better quality of measure of BA FRM performance in the EI, WI, and TI as benchmarked against the IFRM for events in the 2017 operating year. BAL-003-1.1 should continue to utilize the median to measure annual BA FRM performance under the current construct of the standard.

The analysis herein uses BAL-003-1.1 frequency event data submitted by BAs in the EI and WI multi-BA Interconnections and the single-BA TI for the 2017 operating year. The 2017 operating year was the first year in which BAL-003-1.1 Requirement 1 was in effect for compliance purposes. BA performance data was submitted in years prior to the 2017 operating year under the BAL-003-1.1 field trial.

The premise of this analysis is that the calculation of frequency response performance at the interconnection level is the most accurate for any single BAL-003-1.1 event since it does not include variables, such as tie line error, metering error, and losses that may be seen at the BA level. The Interconnection frequency response performance measure ($IFRM_{A-B}$) calculates the ratio of the resource or load megawatt (MW) loss that initiated the event to the difference of predisturbance frequency (Value A) and the stabilizing period frequency (Value B). Value A and Value B are average frequencies from t_{-16} to t_{-2} and t_{+20} to t_{+52}, respectively, as defined in BAL-003-1.1. The MW loss experienced by the Interconnection that initiated the event must be determined in order to calculate $IFRM_{A-B}$ frequency response performance. Below is the equation for calculating $IFRM_{A-B}$.

$$IFRM_{A-B} = \frac{MW\ Loss}{10 * \Delta f_{A-B}}$$

Where:

MW Loss = Resource or Load Output immediately prior to the start of the event

f_{A-B} = Change in frequency from Value A to Value B

[7] Order No. 794, at P 34.

[8] *Id.*

This analysis compared the IFRM for each BAL-003-1.1 frequency event in the 2017 operating year to the aggregate performance for all BAs in the Interconnection for the same event. NERC analyzed BAL-003-1.1 events in EI, WI, and TI. The following reflects the analysis method:

- For analysis of the regression method the IFRM was plotted on the X-axis and the aggregated BA FRM performance is plotted on the Y-axis. The slope of the linear regression was calculated with the Y-intercept set to zero.
- For analysis of the median method the aggregated BA FRM performance was normalized for each event by dividing it by the IFRM for that event. The median of all aggregated BA FRM normalized events was then calculated.
- The results of the regression and median analyses are compared where the method that produces the outcome closest to 1.0 is considered to provide a better quality of measure as benchmarked against the IFRM.

The analyses of BAL-003-1.1 frequency events for the EI, WI, and TI produced consistent results as shown in **Table 1.1**. The median method produced the results closest to 1.0 for all three Interconnections using the aforementioned approach, suggesting that it produces a better quality of measurement than regression. The data that supports the aforementioned analysis and conclusion can be found in **Appendix A** of this report.

Table 1.1: Median versus Regression Analysis

Interconnection	Median	Regression	Preferred Method
Eastern	0.9784	0.9599	Median
Western	1.0138	1.0512	Median
Texas	0.9926	0.9895	Median

Conclusion

The median method provided a better quality of measure of BA FRM performance in the EI, WI, and TI as benchmarked against the IFRM for frequency events in the 2017 operating year. BAL-003-1.1 should continue to utilize the median to measure annual BA FRM performance under the current construct of the standard.

Availability of Frequency Response Resources

FERC Order No. 794 directed NERC to submit an evaluation of "the availability of resources for applicable entities to meet the Frequency Response Obligation."[9] The Commission "direct[ed] NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation."[10] Based on its analysis, NERC concludes that an adequate availability of frequency responsive resources existed in the 2017 operating year for each BA to meet their FROs.

Adequate frequency responsive resources were available during the first year of BAL-003-1.1 implementation for BAs to meet their FROs.

The analysis herein used BAL-003-1.1 frequency event data submitted by BAs for the 2017 operating year and BA FERC Form 714 load and generation data for the 2016 reporting year. The analysis focused on the 34 BAs in the EI and 38 BAs in the WI and evaluated the individual BA FRM compared to their FRO in 2017 under BAL-003-1.1. In addition, FERC Form 714 data was used to assess whether a BA's percentage of total Interconnection generation (MWh) was less than their percentage of the total IFRO. The FRM performance

[9] Order No. 794, at P 3.
[10] Order No. 794, at P 60.

of the single-BA TI exceeded its FRO throughout the 2017 operating year and as such was not pertinent to this analysis.

In the EI, there were only two BAs whose FRM performance did not meet their FRO. Both are small BAs with combined FROs of less than 0.1 percent of the total IFRO. Only one of these BAs had a percentage of interconnection generation that was less than their percentage of IFRO. Further, neither of these two BAs used the transfer of frequency response from other BAs in the Interconnection to meet their FRO. As a result, these two BAs appeared to be outliers, and their performance issue did not indicate an elevated reliability risk to the BPS or lack of available frequency response resources in their Interconnection. Fifteen of the 34 BAs in the EI had a smaller percentage of Interconnection generation than their percentage of IFRO as reported on FERC Form 714 for the 2016 reporting year. Of these 15 BAs, only one BA had an FRM performance that did not meet their FRO. None of the BAs in the EI used the transfer of frequency response for any events in the 2017 operating year.

In the WI, there were no BAs whose FRM performance did not meet their FRO. Twenty of the 38 BAs in the WI had a smaller percentage of Interconnection generation than their percentage of IFRO as reported on FERC Form 714s for the 2016 reporting year. Of these 20 BAs, none had an FRM performance that did not meet their FRO as previously noted. Eleven of the BAs in the WI used the transfer of frequency response for at least one event in the 2017 operating year. In the 2018 operating year the total WI FBS increased nearly 14 percent from the previous year. This is because increased frequency response performance for BAL-003-1.1 resulted in more BAs using a FBS between 100 percent and 125 percent of their previous operating year's FRM (in accordance with the standard) in lieu of a FBS based on the Interconnection minimum. The data that supports the aforementioned analysis and conclusion can be found in **Appendix A** of this report.

Conclusion

NERC concludes that adequate frequency responsive resources were available during the first year of BAL-003-1.1 implementation for all BAs to meet their FROs. This is also true for BAs whose percentage of Interconnection generation was less than their percentage of IFRO. The results of this analysis are only applicable for the historic 2017 operating year and may not be representative of future years where changes in the resource mix, increases in inverter-based resource penetration, and increasingly diverse dispatch patterns may occur. These issues, including the issue of availability versus capability are discussed further in this report.

Chapter 2: BAL-003-1.1 Standard Authorization Requests

NERC received two standards authorization requests (SARs) proposing modifications to *Reliability Standard BAL-003-1.1*. The first SAR[11] was submitted by the NERC Resources Subcommittee (RS) and was posted for industry comment from June 19, 2017, through July 18, 2017. The second SAR[12] was submitted by the Northwest FRSG and was posted for industry comment from November 2, 2017 through December 1, 2017. This SAR proposes a two-phase approach to modifying the current standard.

The recommendations detailed in this report provide technical support for the scope defined in the consolidated SAR.

In addition, several issues highlighted in these two SARs were anticipated and raised in more detail in the NERC *2016 Frequency Response Annual Analysis* (FRAA), which was accepted by the RS on August 25, 2016, and by the NERC Operating Committee on September 30, 2016, and filed with the Commission on October 21, 2016. The SARs and FRAA reflect better understanding of frequency response calculations (including calculation of IFRO) now that Reliability Standard BAL-003-1.1 has been implemented. Several of these lessons learned and findings are referenced above. Now that the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified in the standard and its supporting documents. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified.

Based on comments received from the postings, the NERC RS SAR and the Northwest FRSG SAR have been consolidated by the SAR drafting team to create a new SAR (the consolidated SAR). Phase I of the consolidated SAR proposes revisions to BAL-003-1.1 and process documents to address the following:

- The inconsistencies in calculation of IFROs due to Interconnection frequency response performance changes of Point C and/or Value B
- The Interconnection resource contingency protection criteria
- The frequency nadir point limitations (currently limited to t0 to t+12)
- Clarification of language in Attachment A (i.e., related to FRSG and the time line for frequency response and frequency bias setting activities)
- Enhancement of BAL-003-1 FRS Forms (including the ability to collect and submit FRSG performance data)
- Removal of administrative processes from Attachment A to an ERO approved reference document

The scope of the work identified in the second phase, Phase II of the Consolidated SAR, proposes that the standard drafting team (SDT) evaluate modifications to BAL-003-1.1 to do the following:

- Establish a real-time Reliability Standard addressing the necessary frequency response to maintain reliability.
- Establish comparability for the appropriate responsible entities.
- Develop real-time measurements incorporating topology difference.
- Eliminate the incorrect indicators.

The SDT is now pursuing the objectives laid out in the consolidated SAR.

[11] https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_SAR_June_2017.pdf
[12] https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_SAR_NWPP_Nov2017.pdf

Appendix A: Supporting Data

Regression versus Median Statistical Method Analysis—Eastern Interconnection

Table A.1: EI Statistical Method Analysis

EI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	Aggregated BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	Aggregated BA FRM Normalized by IFRM		
31-Dec-16	2,615	2,667	1.0199	MEDIAN	0.9784
10-Jan-17	2,819	2,322	0.8237	REGRESSION	0.9599
12-Jan-17	3,125	2,281	0.7299		
26-Jan-17	2,335	2,587	1.1077		
28-Jan-17	1,637	2,239	1.3677		
14-Feb-17	2,736	2,776	1.0145		
22-Feb-17	2,692	2,697	1.0019		
25-Feb-17	1,269	1,222	0.9634		
7-Mar-17	2,088	2,007	0.9615		
20-Mar-17	3,194	3,212	1.0056		
8-Apr-17	1,660	1,578	0.9506		
11-Apr-17	1,889	2,453	1.2987		
26-Apr-17	1,645	1,223	0.7434		
18-May-17	1,398	1,339	0.9576		
22-May-17	2,920	2,351	0.8053		
8-Jun-17	2,208	2,718	1.2310		
19-Jun-17	2,143	2,539	1.1849		
24-Jun-17	2,548	2,170	0.8518		
17-Jul-17	3,133	3,019	0.9635		
21-Jul-17	3,863	2,661	0.6890		
27-Aug-17	2,540	2,429	0.9562		
28-Aug-17	2,173	2,163	0.9951		
2-Sep-17	2,317	2,365	1.0208		
8-Oct-17	1,369	2,344	1.7124		
26-Oct-17	1,683	1,456	0.8648		
7-Nov-17	1,625	1,222	0.7517		
7-Nov-17	2,286	2,236	0.9784		
8-Nov-17	2,473	2,794	1.1301		
20-Nov-17	1,813	2,128	1.1739		

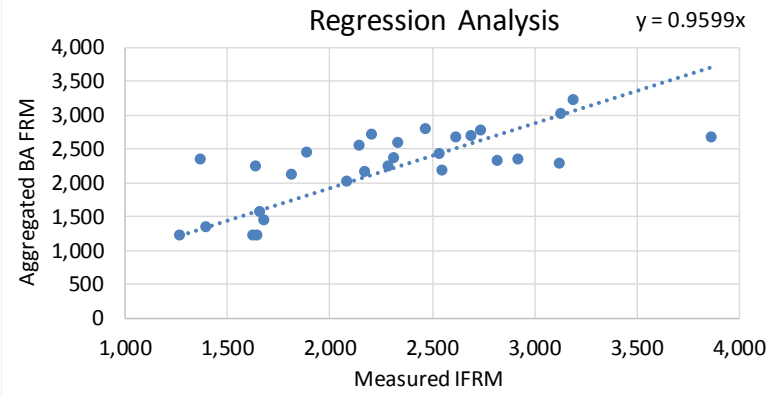


Figure A.1: EI Regression Analysis

Regression versus Median Statistical Method Analysis—Western Interconnection

Table A.2: WI Statistical Method Analysis

WI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	Aggregated BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	Aggregated BA FRM Normalized by IFRM		
19-Jan-17	2,536	1,532	0.60	MEDIAN	1.0138
20-Jan-17	1,838	1,670	0.91	REGRESSION	1.0512
24-Jan-17	2,676	2,932	1.10		
6-Feb-17	1,567	1,769	1.13		
6-Feb-17	1,382	1,371	0.99		
4-Mar-17	2,904	2,235	0.77		
8-Mar-17	1,722	1,947	1.13		
9-Mar-17	1,384	1,602	1.16		
17-Mar-17	1,691	1,420	0.84		
7-Apr-17	1,703	1,667	0.98		
14-Apr-17	1,250	1,234	0.99		
8-Jun-17	3,064	2,727	0.89		
15-Jun-17	1,215	1,170	0.96		
16-Jun-17	2,165	2,181	1.01		
19-Jun-17	1,728	2,385	1.38		
23-Jun-17	2,219	2,707	1.22		
4-Jul-17	1,358	1,540	1.13		
15-Jul-17	1,539	1,560	1.01		
29-Jul-17	2,158	2,233	1.03		
30-Jul-17	1,868	1,820	0.97		
8-Aug-17	1,527	1,763	1.15		
10-Sep-17	2,175	2,072	0.95		
15-Sep-17	2,286	3,033	1.33		
20-Sep-17	6,645	7,650	1.15		
24-Nov-17	1,709	2,082	1.22		

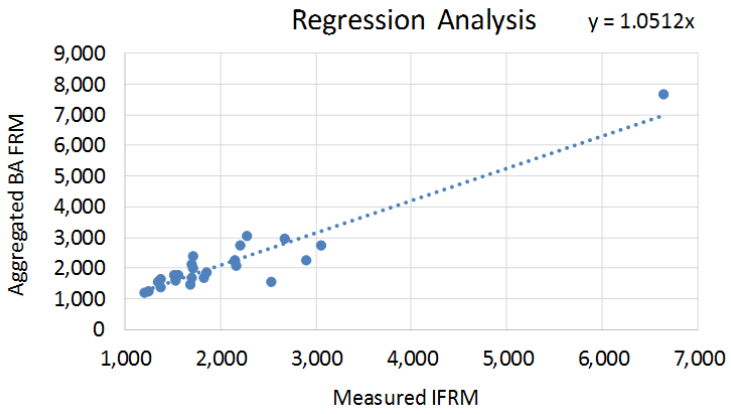


Figure A.2: WI Regression Analysis

Regression versus Median Statistical Method Analysis—Texas Interconnection

Table A.3: TI Statistical Method Analysis

TI Event 2017 OY	Measured IFRM Abs (MW/0.1Hz)	BAL-003-1.1 BA FRM Abs (MW/0.1Hz)	BAL-003 BA FRM Normalized by IFRM		
23-Dec-16	570	566	0.9931	MEDIAN	0.9926
7-Jan-17	840	843	1.0038	REGRESSION	0.9895
24-Jan-17	2,041	2,016	0.9877		
14-Feb-17	520	519	0.9981		
20-Feb-17	780	774	0.9926		
10-Mar-17	823	820	0.9965		
15-Mar-17	670	673	1.0045		
30-Mar-17	909	908	0.9991		
10-Apr-17	731	585	0.7999		
13-Apr-17	514	504	0.9811		
16-Apr-17	491	496	1.0095		
26-Apr-17	1,123	1,135	1.0109		
11-May-17	732	711	0.9709		
19-May-17	919	898	0.9779		
21-May-17	700	697	0.9961		
2-Jun-17	727	736	1.0115		
6-Jun-17	611	604	0.9895		
7-Jun-17	1,124	1,110	0.9880		
11-Jun-17	671	659	0.9816		
12-Jun-17	750	751	1.0008		
16-Jun-17	1,447	1,426	0.9853		
27-Jun-17	792	798	1.0074		
2-Jul-17	773	782	1.0113		
26-Jul-17	702	693	0.9868		
9-Aug-17	631	615	0.9752		
23-Aug-17	797	799	1.0019		
1-Sep-17	1,037	1,013	0.9762		
2-Sep-17	1,450	1,438	0.9917		
9-Sep-17	1,221	1,194	0.9781		
6-Oct-17	839	845	1.0066		
8-Oct-17	1,116	1,123	1.0059		
30-Oct-17	684	685	1.0009		
6-Nov-17	764	759	0.9936		
13-Nov-17	687	682	0.9921		
18-Nov-17	641	636	0.9923		
26-Nov-17	991	996	1.0049		

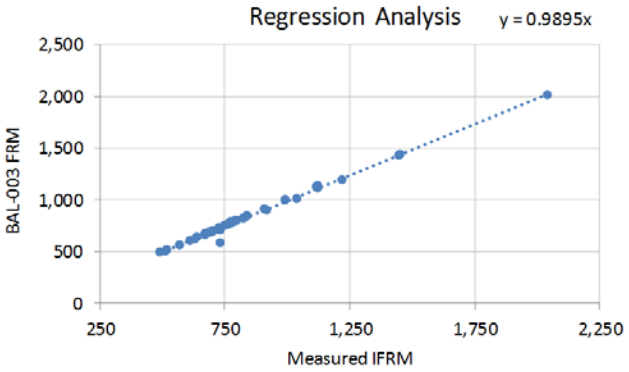


Figure A.3: TI Regression Analysis

Availability of Frequency Response Resources

BAs whose percentage of Interconnection generation was less than their percentage of IFRO as reflected on the FERC Form 714 submittals for the 2016 reporting year, are highlighted in red. See **Table A.4** and **Table A.5**.

Table A.4: EI Availability Analysis

2017 OY		Total $Gen_{BA}/TotalGen_{Int}$ Source: 2016 FERC 715
	FRM/FRO	% Int Generation - %IFRO
EI BA1	156%	-0.212%
EI BA2	230%	-0.007%
EI BA3	486%	0.090%
EI BA4	284%	-0.007%
EI BA5	-113%	-0.010%
EI BA6	406%	-0.019%
EI BA7	1105%	-0.010%
EI BA8	180%	0.169%
EI BA9	147%	-0.004%
EI BA10	125%	0.020%
EI BA11	546%	-0.642%
EI BA12	221%	0.181%
EI BA13	355%	-0.003%
EI BA14	290%	-0.315%
EI BA15	254%	-0.347%
EI BA16	297%	0.002%
EI BA17	217%	-0.006%
EI BA18	179%	0.255%
EI BA19	517%	0.158%
EI BA20	145%	0.291%
EI BA21	116%	0.014%
EI BA22	184%	0.032%
EI BA23	2296%	0.041%
EI BA24	168%	0.034%
EI BA25	265%	0.053%
EI BA26	412%	0.038%
EI BA27	142%	-0.012%
EI BA28	290%	0.040%
EI BA29	301%	-0.102%
EI BA30	-102%	0.030%
EI BA31	137%	0.154%
EI BA32	248%	-0.015%
EI BA33	500%	0.092%
EI BA34	170%	0%

Table A.5: WI Availability Analysis		
2017 OY		Total $Gen_{BA}/TotalGen_{Int}$ Source: 2016 FERC 715
	FRM/FRO	% Int Generation - % IFRO
WI BA1	317%	0.089%
WI BA2	192%	0.004%
WI BA3	307%	-0.058%
WI BA4	403%	-0.223%
WI BA5	257%	3.362%
WI BA6	161%	-3.461%
WI BA7	100%	-0.074%
WI BA8	202%	-0.262%
WI BA9	249%	0.102%
WI BA10	497%	0.414%
WI BA11	246%	0.036%
WI BA12	133%	-0.077%
WI BA13	103%	-0.121%
WI BA14	333%	-0.239%
WI BA15	100%	0.033%
WI BA16	270%	0.042%
WI BA17	235%	-0.297%
WI BA18	176%	0.197%
WI BA19	210%	0.003%
WI BA20	276%	-0.003%
WI BA21	189%	-0.086%
WI BA22	255%	-0.391%
WI BA23	120%	-0.244%
WI BA24	236%	0.037%
WI BA25	132%	0.254%
WI BA26	193%	0.234%
WI BA27	397%	0.053%
WI BA28	144%	-0.462%
WI BA29	287%	-0.070%
WI BA30	280%	-0.132%
WI BA31	280%	-0.007%
WI BA32	181%	-0.062%
WI BA33	283%	-0.040%
WI BA34	307%	0.840%
WI BA35	333%	-0.017%
WI BA36	156%	0.160%
WI BA37	213%	0.421%
WI BA38	220%	0.020%

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD BAL-002-3

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August 17, 2018

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY **2**

II. NOTICES AND COMMUNICATIONS **4**

III. BACKGROUND **4**

A. REGULATORY FRAMEWORK **4**

B. NERC Reliability Standards Development Procedure **5**

C. Procedural History of Proposed Reliability Standard BAL-002-3 ..... **6**

IV. JUSTIFICATION FOR APPROVAL **7**

A. Proposed Reliability Standard BAL-002-3 ..... **7**

B. Justification for Proposed Reliability Standard BAL-002-3 ..... **9**

C. Enforceability of Proposed Reliability Standard BAL-002-3 ..... **10**

V. EFFECTIVE DATE **11**

VI. CONCLUSION **11**

Exhibit A Proposed Reliability Standard BAL-002-3
Exhibit B Implementation Plan
Exhibit C Order No. 672 Criteria
Exhibit D Summary of Development and Complete Record of Development
Exhibit E Rationale for BAL-002-3
Exhibit F Standard Drafting Team Roster

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD BAL-002-3

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby requests that the Commission approve: (i) proposed Reliability Standard BAL-002-3 (Disturbance Control Performance – Contingency Reserve for Recovery from a Balancing Contingency Event) (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest; (ii) the associated Implementation Plan (**Exhibit B**); and (iii) the retirement of currently-effective Reliability Standard BAL-002-2. Proposed Reliability Standard BAL-002-3 will apply the same Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") as applicable to currently effective Reliability Standard BAL-002-2. Therefore, this petition does not include a separate justification for the VRFs and VSLs.

As required by section 39.5(a) of the Commission's regulations,[4] this Petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[5]

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2017).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006). Terms not otherwise defined herein, are defined in the proposed Reliability Standard BAL-002-3 and the NERC Glossary.

4 18 C.F.R. § 39.5(a).

5 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability*

(**Exhibit C**), and a summary of the standard development history (**Exhibit D**). The proposed Reliability Standard was adopted by the NERC Board of Trustees on August 16, 2018.

I. EXECUTIVE SUMMARY

Reliable operation of the Bulk Power System depends on the ability of responsible entities to balance resources and demand and to recover from a system contingency through frequency restoration and the deployment of reserves necessary to replace lost capacity and energy. Reliability Standard BAL-002-3 is designed to ensure that "the Balancing Authority [("BA")] or Reserve Sharing Group [("RSG")] balances resources and demand and returns the [BA]'s or [RSG]'s Area Control Error [("ACE")] to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event." To support this goal, Requirement R1 mandates certain actions upon a Reportable Balancing Contingency Event to (i) return Reporting ACE to defined values within the Contingency Event Recovery Period; (ii) document Reportable Balancing Contingency Events; and (iii) deploy Contingency Reserves. Within this rubric, Requirement R1 Part 1.3 provides a limited exemption from the BA's or RSG's obligation to restore Reporting ACE within the Contingency Event Recovery Period if the entity is recovering from an emergency event under NERC Emergency Preparedness and Operations ("EOP') Reliability Standards and meets certain other qualifications.

In Order No. 835, the Commission approved Reliability Standard BAL-002-2 while highlighting the "need to address the underlying concern . . . that a balancing authority that is operating out-of-balance for an extended period of time is 'leaning on the system' . . . ."[6] Accordingly, the Commission directed NERC to revise the standard to require an entity seeking

Standards, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672").

[6] *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, Order No. 835, 158 FERC ¶ 61,030, at P 35 (2017) ("Order No. 835").

to avail itself of the exemption in Requirement R1.3 "to obtain an extension of the 15-minute ACE recovery period by informing the reliability coordinator [("RC")]of the circumstances and providing it with an ACE recovery plan and target time period."[7]

In response to Order No. 835, NERC established Project 2017-06 to develop revisions to Reliability Standard BAL-002-2 to implement the Commission's directive. The standard drafting team's ("SDT's") proposed modifications also intend to clarify that communication with the RC should proceed in accordance with Energy Emergency Alert procedures within the EOP Reliability Standards. The proposed modifications would ensure that Reliability Standard BAL-002-3 addresses the Commission's concern in a manner that coordinates with emergency procedures in other Reliability Standards. NERC respectfully requests that the Commission approve proposed Reliability Standard BAL-002-3 and the associated Implementation Plan as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

[7] *Id.*

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

A. REGULATORY FRAMEWORK

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[9] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[10] Section 39.5(a) of the Commission's regulation requires the ERO to file for Commission approval of each Reliability Standard that the ERO proposes should

[8] 16 U.S.C. § 824o.
[9] *Id*. § 824o(b)(1).
[10] *Id*. § 824o(d)(5).

become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.[11]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the Reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c) of the Commission's regulations, "the Commission will give due weight to the technical expertise of the Electric Reliability Organization" with respect to the content of a Reliability Standard.[13]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of the NERC Rules of Procedures ("ROP") and the NERC Standard Processes Manual ("SPM").[15]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[16] and thus

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11 18 C.F.R. § 39.5(a).

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1).

14 Order No. 672 at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

15 The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

16 Order No. 672 at P 268.

satisfy the criteria for approving Reliability Standards.[17] The ANSI-accredited development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. Before a Reliability Standard is submitted to the Commission for approval, NERC must consider the comments of all stakeholders, the stakeholders must approve of the Standard, and the Standard must be adopted by the NERC Board of Trustees.

C. Procedural History of Proposed Reliability Standard BAL-002-3

In Order No. 835, the Commission approved Reliability Standard BAL-002-2, noting that it "improve[d] 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."[18] In addition, the Commission directed NERC to: (i) change proposed VRFs for Requirements R1 and R2 from "medium" to "high";[19] (ii) collect and report on certain data pertaining to implementation of the standard within two years from Reliability Standard BAL-002-2 implementation;[20] and (iii) develop modifications to the standard to "require an entity to provide certain information to the reliability coordinator when the entity does not timely recover ACE due to an intervening disturbance."[21]

With regard to modifications to the standard, the Commission:

> [D]irect[ed] 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.[22]

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17 *Id*. at PP 268, 270.

18 Order No. 835 at P 21.

19 *Id*. at P 68. NERC has revised the standard in accordance with this directive. *See NERC*, Docket No. RD17-6-000 (Oct. 2, 2017) (Letter Order) ("Order No. 835 Letter Order").

20 Order No. 835 at P 46. NERC is collecting data pursuant to this directive and plans to submit an informational filing by the Commission's deadline January 2, 2020.

21 *Id*. at P 2; *see also id.* at P 35.

22 Order No. 835 at P 37.

In response to this directive, NERC established Project 2017-06 and the SDT developed modifications to Reliability Standard BAL-002-2 that would require notification to the RC in accordance with the Commission's directive, while leveraging Energy Emergency Alert procedures in the EOP Reliability Standards. Following two comment and ballot periods, proposed Reliability Standard BAL-002-3 was approved by the ballot pool by July 16, 2018. The NERC Board of Trustees adopted the Standard and Implementation Plan on August 16, 2018.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in **Exhibit C**, proposed Reliability Standard BAL-002-3 addresses the Commission's directive in Order No. 835, satisfies the Commission's criteria in Order No. 672, and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following subsections provide: (A) a description of the proposed standard; (B) justification for the modifications in the proposed standard; and (C) discussion of the enforceability of the proposed standard.

A. Proposed Reliability Standard BAL-002-3

Proposed Reliability Standard BAL-002-3 is designed to ensure that a BA or RSG balances resources and demand and returns the ACE to defined values following a Reportable Balancing Contingency Event.[23] It applies to BAs and RSGs (noting that a BA that is a member of an RSG is the responsible entity only in periods during which the BA is not in active status under the RSG). The primary objective of the proposed standard is to ensure that the responsible entity is prepared to balance resources and demand by requiring the maintenance of adequate

[23] *See* Exhibit E, Rationales for BAL-002-3 (Feb. 2018).

reserves and the deployment of those reserves to return its ACE to defined values following a Reportable Balancing Contingency Event.

In support of this objective, Requirement R1 obligates responsible entities to: (i) return Reporting ACE to certain values within the Contingency Event Recovery Period (Requirement R1 Part 1.1); (ii) document Reportable Balancing Contingency Events (Requirement R1 Part 1.3); and (iii) deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events (Requirement R1 Part 1.3). Within this framework, Requirement R1 Part 1.3.1 also permits an exemption from a responsible entity's obligation to demonstrate recovery of Reporting ACE within the Contingency Event Recovery Period under certain limited circumstances associated with an emergency on the system. In accordance with the Commission's directive in Order No. 835, the SDT has proposed the following modifications to further limit Requirement R1 Part 1.3.1:

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

….

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

B. Justification for Proposed Reliability Standard BAL-002-3

As discussed above, in Order No. 835, the Commission expressed concern that "a balancing authority that is operating out-of-balance for an extended period of time is 'leaning on the system'"[24] and directed NERC to:

> [R]equire 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 . . . .[25]

[24] Order No. 835 at P 35.
[25] *Id*. at P 37.

In response, the drafting team modified Requirement R1 Part 11.3.1 of Reliability Standard BAL-002-2 to clarify and narrow conditions when a BA or RSG may qualify for an exemption from the time period for recovery of Reporting ACE otherwise applicable under Requirement R1 Part 1.1 due to emergency conditions. Consistent with the Commission's directive, with the modifications in the proposed Reliability Standard, a BA or RSG may only be exempt from Requirement R1 Part 1.1 if it provides the RC (1) notice of the conditions warranting an exemption, and (2) an ACE recovery plan. Proposed Reliability Standard BAL-002-3 thereby improves upon BAL-002-2 by ensuring coordination with the Reliability Coordinator before a responsible entity may avail itself of the exemption in Requirement R1.3.1 and addressing concerns that a responsible entity taking advantage of the exemption is "leaning on the system."

C. Enforceability of Proposed Reliability Standard BAL-002-3

The proposed Reliability Standard BAL-002-3 includes measures that support each Requirement to provide guidance to the industry about compliance expectations and to ensure that the Requirements are enforced in a clear, consistent, non-preferential manner, and without prejudice to any part. The proposed Reliability Standard VRFs and VSLs associated with each Requirement are amongst several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability caused by violations of a specific Requirement. The VSLs guide the method by which NERC will enforce the Requirements of the proposed Reliability Standards. In this Petition, NERC proposes to utilize the same VRFs and VSLs in effect for BAL-002-2. These VRFs and VSLs were approved

in 2017.[26] Therefore, the VRFs and VSLs in proposed Reliability Standard BAL-002-3 comport with NERC and Commission Guidelines.

V. EFFECTIVE DATE

NERC Respectfully requests that the Commission approve proposed Reliability Standard BAL-002-3, effective on the first day of the first calendar quarter that is six calendar months after the effective date of the Commission's order approving the standard and terms, or as otherwise provided for by the applicable governmental authority. This will provide for deliberative implementation of the revised Requirement. In addition, NERC requests retirement of Reliability Standard BAL-002-2. Proposed Reliability Standard BAL-002-3 will replace and supersede currently-effective Reliability Standard BAL-002-2.

VI. CONCLUSION

NERC has developed these modifications to Reliability Standard BAL-002-3 to address the Commission's directive in Order No. 835 and provide RCs with important information necessary for coordinated operations of the grid, while maintaining an appropriate level of flexibility for responsible entities faced with an emergency on the system. For the reasons set forth above, NERC respectfully requests that the Commission approve (i) proposed Reliability Standard BAL-002-3 (**Exhibit A**); (ii) the Implementation Plan (**Exhibit B**); and (iii) the retirement of currently-effective Reliability Standard BAL-002-2.

[26] Violation Risk Factors were updated after the adoption of BAL-002-2 as per Commission directives in Order No. 835. *See* Order No. 835 Letter Order.

Respectfully submitted,

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Date: August 17, 2018

Exhibit A

Proposed Reliability Standard

Exhibit A

Proposed Reliability Standard

BAL-002-3 (Disturbance Control Performance –

Contingency Reserve for Recovery from a Balancing Contingency Event)

Clean

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. 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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. 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, 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. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	
3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	TBD	FERC Order approving BAL-002-3	

Exhibit A

Proposed Reliability Standard

BAL-002-3 (Disturbance Control Performance –

Contingency Reserve for Recovery from a Balancing Contingency Event)

Redline

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-32

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-32.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that~~the Responsible Entity~~:

- is ~~a Balancing Authority~~ experiencing a Reliability Coordinator declared Energy Emergency Alert Level ~~or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level~~, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. 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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. 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, 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. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	
3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	TBD	FERC Order approving BAL-002-3	

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

Exhibit C

Order No. 672 Criteria

Exhibit C

Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[1] The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specific reliability goal and must contain a technically sound means to achieve that goal.[2]**

Proposed Reliability Standard BAL-002-3 achieves the specific reliability goal of ensuring that the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a reportable Balancing Contingency Event. Proposed Reliability Standard BAL-002-3 tightens an exception to BAL-002 Requirement R1 (as expressed in Requirement R1 Part 1.3.1) in which a Responsible Entity (Balancing Authority or Reserve Sharing Group) receives relief from compliance to Requirement R1 during a Reportable Balance Contingency Event in which that Responsible Entity is (1) 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, or (3) has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, by requiring that the Responsible Entity notify the Reliability Coordinator that the Responsible

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

Entity is experiencing the aforementioned conditions, and to provide the Reliability Coordinator with an ACE recovery plan, including a target recovery time.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard applies to Reserve Sharing Groups and a Balancing Authorities, but a Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard, each of which are triggered by articulable actions.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]**

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required to demonstrate compliance and how the Requirement will be enforced. The Measures are as follows:

> **M1.** Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.
>
> **M2.** Each Responsible Entity will have the following documentation to show compliance with Requirement R2:
> - a dated Operating Process;
> - evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
> - evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.
>
> **M3.** Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

The Above Measures work in coordination with the respective Requirements to ensure that the Requirements will each be enforced in a clear, consistent, and non-preferential manner without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently – but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]**

The proposed Reliability Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the

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[5] Order No. 672 at P 327.
[6] Order No. 672 at P 328.

responsibilities of applicable entities with respect to balancing resources and demands, including deployment and subsequent recovery of adequate levels of Contingency Reserves, to return the Area Control Error to defined values. The proposed Reliability Standard provides entities with the flexibility to tailor their processes and plans to take into account system dynamics and characteristics while still maintaining reliability of the Bulk Power System.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power system reliability. Proposed Reliability Standards can consider costs to implement for smaller entities but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed standard represents significant benefits for the reliability of the Bulk Power System because it requires entities to protect system stability by recovering an entity's Reporting Area Control Error and requisite levels of Contingency Reserves. The proposed Reliability Standard does not sacrifice excellence in operating system reliability for costs associated with implementation of the Reliability Standard.

7. **Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

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[7] Order No. 672 at P 329-30.

[8] Order No. 672 at P 331.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**[9]

The proposed Reliability Standard has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each applicable entity. The standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.**[10]

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. The proposed Implementation Plan, attached as **Exhibit B**, will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective date is explained in the attached Implementation Plan for BAL-002-3

10. **The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.**[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission approved, ANSI-accredited processes for developing and approving Reliability Standards.[12] **Exhibit D** includes a summary of the Reliability Standard development proceedings and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods.

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9 Order No. 672 at P 332.
10 Order No. 672 at P 333.
11 Order No. 672 at P 334.
12 *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of proposed Reliability Standard BAL-002-3. No comments were received that indicated the proposed Reliability Standard BAL-002-3. No comments were received that indicated the proposed Reliability Standard conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

NERC has identified no other factors relevant to whether the proposed Reliability Standard BAL-002-3 is just and reasonable.

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[13] Order No. 672 at P 335.

[14] Order No. 672 at P 323.

Exhibit D

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard BAL-002-3 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Standard Drafting Team is included in Exhibit F.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for Project 2017-06 – Modifications to BAL-002-2 - Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event was posted for a 30-day comment period from June 20, 2017 through July 20, 2017. The final SAR was posted on March 13, 2018. Following two solicitations for nominations, the Standards Committee ("SC") appointed a SAR drafting team at its October 18, 2017 meeting. The SAR was approved by the SC on February 14, 2018.

B. First Posting – Comment Period, Initial Ballot and Non-binding Poll

Proposed Reliability Standard BAL-002-3, the associated Implementation Plan, and the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") were posted for a 45-

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d) (2) (2012).

[2] The NERC Standard Processes Manual is available at https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

day formal public comment period from March 22, 2018 through May 8, 2018, with a parallel Initial Ballot and Non-binding Poll held during the last 10 days of the comment period from April 27, 2018 through May 7, 2018. The initial ballot received 81.82% quorum, and 69.46% approval. The non-binding pill received 80% quorum and 77.19% of supportive opinions. There were 30 responses, including comments from approximately 115 different individuals and approximately 87 companies representing all 10 industry segments.[3]

C. Final Draft

Proposed Reliability Standard BAL-002-3 was posted for a 10-day final ballot period from July 5, 2018 through July 16, 2018. The Proposed Reliability Standard received a quorum of 84.42% and an approval rating of 71.85%.

D. Board of Trustees Approval

Proposed Reliability Standard BAL-002-3 was adopted by the NERC Board of Trustees on August 16, 2018.[4]

[3] NERC, Consideration of Comments, Project 2017-06 - – Modifications to BAL-002-2, https://www.nerc.com/pa/Stand/Project_201706_Modifications_to_BAL0022_DL/2017-06_Mod_to_BAL-002_Consideration_of_Comments_07052018.pdf.

[4] NERC, Board of Trustees Agenda Package, Agenda Item 7c (BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_August_16_2018.pdf.

Complete Record of Development

Project 2017-06 Modifications to BAL-002-2

Related Files

Status

The final ballot for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** concluded **8 p.m. Eastern, Monday, July 16, 2018.** The voting results are available via the link below. The standard will be submitted to the Board of Trustees for adoption then filed with the appropriate regulatory authorites.

Background

On January 19, 2017, FERC issued an order approving Reliability Standard BAL-002-2. FERC Order also directed NERC to make two modifications to the BAL-002-2 standard and revise two VRFs. The revision for the VRFs will be handled outside of this SAR.

With regard to FERC's directed modifications to BAL-002-2, the order stated:

"Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (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."

Standard(s) Affected – BAL-002-2

Purpose / Industry Need

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft BAL-002-3 Clean **(23)** | Redline **(24)** to Last Approved Implementation Plan **(25)**	Final Ballot Info **(26)** Vote	07/05/18 - 07/16/18	Ballot Results **(27)**	
Draft 1 BAL-002-3 Clean **(11)** | Redline **(12)** to Last Approved	Initial Ballot and Non-binding Poll	04/27/18 - 05/08/18	Ballot Results **(18)** Non-binding Poll Results **(19)**	

Implementation Plan **(13)** **Supporting Materials** Unofficial Comment Form (Word) **(14)** Rationales for BAL-002-3 **(15)**	Updated Info **(16)** Info **(17)** Vote	Extended an additional day to reach quorum		
	Comment Period Info **(20)** Submit Comments	03/22/18 - 05/08/18	Comments Received **(21)**	Consideration of Comments**(22)**
	Join Ballot Pools	03/22/18 - 04/20/18		
Standards Authorization Request **(10)**	For Informational Purposes Only	03/13/18		
Supplemental Standards Authorization Request Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(8)**	Supplemental Nomination Period Info **(9)** Submit Nominations	07/27/17 - 08/09/17		

Standards Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	06/20/17 - 07/20/17	Comments Received **(6)**	Consideration of Comments **(7)**
Standards Authorization Request Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	06/20/17 - 07/03/17		

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Monday, July 3, 2017.** 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 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

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 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (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."

The time commitment for this project 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 review and 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.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Standards affected: BAL-002-2

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 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:	

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Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Nomination Period Open through July 3, 2017

Now Available

Nominations are being sought for Standards Authorization Request drafting team members through **8 p.m. Eastern, Monday, July 3, 2017**.

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 Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 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 Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-002-2 – Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event		
Date Submitted:			
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC Staff		
Telephone:	609.613.1848	Email:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated: "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with

SAR Information
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." Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 158 FERC ¶ 61,030 at P 37 (2017) ("FERC Order"). *See also, id.*, at P 2 and PP 35-36.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the standard, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address the FERC Order directives described above or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address either (A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or (B) proposing an equally efficient and effective alternative.

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

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.		Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.		Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.		Yes

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.

Regional Variances	
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

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Unofficial Comment Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request

Do not use this form for submitting comments. Use the electronic form to submit comments on the Standards Authorization Request (SAR) for **BAL-002-2 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**. The electronic form must be submitted by **8 p.m. Eastern, Thursday, July 20, 2017**.

Documents and information about this project are available on the Project 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (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."

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. Based on the scope of the SAR, do you have any other comments for drafting team consideration?

   ☐ Yes
   ☐ No

   Comments:

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Standards Announcement

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request

Informal Comment Period Open through July 20, 2017

Now Available

A 30-day informal comment period on the Standards Authorization Request (SAR) for **BAL-002-2 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Thursday, July 20, 2017**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
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Comment Report

Project Name:	2017-06 Modifications to BAL-002-2 | Standards Authorization Request
Comment Period Start Date:	6/20/2017
Comment Period End Date:	7/20/2017
Associated Ballots:	

There were 21 sets of responses, including comments from approximately 72 different people from approximately 48 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

2. Based on the scope of the SAR, do you have any other comments for drafting team consideration?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mahmood Safi	Omaha Public Power District	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer	No
Document Name	

Comment

Currently there is no requirement for a Reserve Sharing Group to have a 24 hour, manned, operations center. This would be required if this proposal is implemented. Furthermore, it would also require the Reserve Sharing Group to have authority in some manner over the participating BAs to devise and implement a recovery plan. A proposed alternative could be that BAs that are a part of a RSG must notify their RC if they will not be able to recover their individual ACE in the recovery period as well as providing their recovery plan and target recovery time.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

Please see response to Queston #2.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

The Cityy Light subjet amtter expert feels that there should be no requirement that forces a Reserve Sharing Group to have a 24 hour a day operations center. An alternative would be for BA's that are part of an RSG and cause the RSG to be in a disturbance provide the Reliability Coordinator with an ACE recovery plan if they will not be able to recover their ACE in 15 minutes.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group recommends that the drafting team provides clarity on what the FERC Order is requiring and the situation that has been identified in Requirement R1 Part 1.3.1 of the Standard. From our perspective, there may be some confusion on what goals that need to be accomplished for a Responsible Entity pertaining to this requirement. It's not clear on if a the event drives the situation in to 1.3.1 or b has the EEA Event already occurred and then the Responsible Entity needs to notify the RC about not meeting their recovery time as well as submitting a Recovery Plan. Also, we recommend that if the FERC Order addresses a then BAL-002-2 may be the appropriate document to conduct the proposed revisions. However, if the concerns are more applicable to b then the group would recommend making the appropriate revisions to the EOP-011-1 Standard.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

We caution the use of "15-minute ACE recovery period" in the SAR. We believe the SDT should have clear direction to instead leverage the previously NERC Glossary-defined term, "Contingency Event Recovery Period." This term is referenced frequently within the standard and aligns with the efforts of the previous Standard Drafting Team.

Likes 0	
Dislikes 0	

Response

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	
Comment	

In its comments to FERC's Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-7-000, Arizona Public Service Company (APS) outlined a proposal regarding notice to the RC when the extenuating conditions listed in Requirement R1.3.1 are met and the BA is unable to recover its ACE within the 15-minute recovery period. This proposal addressed FERC's concerns with extension of the 15-minute ACE recovery period, but also allowed appropriate flexibility to BAs when extenuating circumstances are present. (Order No. 835, P 36.)

NorthWestern Energy agrees with the proposal that was outlined by APS in its comments to the FERC NOPR. (APS Comments, Accession No. 20160720-2146, Section II-A, pages 3–9.)

Likes 0	
Dislikes 0	
Response	

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

2. Based on the scope of the SAR, do you have any other comments for drafting team consideration?	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The IRC Standards Review Committee (SRC) provides these comments: As one of the “alternative modifications” the SRC proposes the SDT consider converting the Standard to a communication guide (developed under the auspices of the NERC OC) that could be converted to a standard if such a need were identified by the RCs.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team evaluate the expansion of SAR that are associated with part 1.3.2 of the Standard. Our concern pertains to contingencies impacting frequency that is outside of the Responsible Entity’s area that has a significant impact on the Responsible Entity meeting the 15 minute recovery.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that the SAR aligns with the directive from FERC, and also agrees with the scope of this project as written currently.	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak appreciates the opportunity to provide comments on the BAL-002-2 SAR. Peak requests consideration be given to intended and/or unintended expectations resulting from the provision of the information to the Reliability Coordinator that may or may not be covered by additional NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
"The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns." Since BAL-002-2 is addressing recovery from a **Reportable** Balancing Contingency Event (as distinct from a separately defined [non-reportable] Balancing Contingency Event), and since the FERC Order requires NERC to develop modifications regarding such **Reportable** events, in order to avoid any ambiguity or confusion we recommend that the SAR Objective be revised to state: "The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a **Reportable** Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns."	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment
PacifiCorp is concerned that (1) the requirement 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, will be distracting requirements as the balancing area operators are working towards recovery in the 15-minute period. Setting aside recovering from the event to provide notification to the reliability coordinator could impede efforts towards the recovery itself. We fail to see the value in these additional requirements and wonder if is this more suitable for the Eastern Interconnection – Western Interconnection power pool agencies are not 7x24 shops.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment
In order to provide clear, unambiguous requirements to address the FERC directive, Texas RE recommends the standard drafting team (SDT) consider specifying a time-frame in which the notification and provision of a recovery plan is expected to occur. Developing a recovery plan and target recovery time may not be feasible within 15 minutes, so it may be more practical to require notification to the Reliability Coordinator (RC) within 15 minutes of the event, and provision of a recovery plan within an agreed upon time-frame.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2017-06 Modifications to BAL-002-2 | Standards Authorization Request
Comment Period Start Date:	6/20/2017
Comment Period End Date:	7/20/2017
Associated Ballots:	

There were 21 sets of responses, including comments from approximately 72 different people from approximately 48 companies representing the 10 Industry Segments as shown in the table on the following pages.

Questions

1. **The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.**

2. **Based on the scope of the SAR, do you have any other comments for drafting team consideration?**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
				Seattle City Light Ballot Body	Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida	6	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Power and Light Co.		
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mahmood Safi	Omaha Public Power District	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. *The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.*

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Currently there is no requirement for a Reserve Sharing Group to have a 24 hour, manned, operations center. This would be required if this proposal is implemented. Furthermore, it would also require the Reserve Sharing Group to have authority in some manner over the participating BAs to devise and implement a recovery plan. A proposed alternative could be that BAs that are a part of a RSG must notify their RC if they will not be able to recover their individual ACE in the recovery period as well as providing their recovery plan and target recovery time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1 with respect to the responsible entity communicating with the RC.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No

Document Name	
Comment	
Please see response to Queston #2.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
The Cityy Light subjet amtter expert feels that there should be no requirement that forces a Reserve Sharing Group to have a 24 hour a day operations center. An alternative would be for BA's that are part of an RSG and cause the RSG to be in a disturbance provide the Reliability Coordinator with an ACE recovery plan if they will not be able to recover their ACE in 15 minutes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment
The SPP Standards Review Group recommends that the drafting team provides clarity on what the FERC Order is requiring and the situation that has been identified in Requirement R1 Part 1.3.1 of the Standard. From our perspective, there may be some confusion on what goals that need to be accomplished for a Responsible Entity pertaining to this requirement. It's not clear on if a the event drives the situation in to 1.3.1 or b has the EEA Event already occurred and then the Responsible Entity needs to notify the RC about not meeting their recovery time as well as submitting a Recovery Plan. Also, we recommend that if the FERC Order addresses a then BAL-002-2 may be the appropriate document to conduct the proposed revisions. However, if the concerns are more applicable to b then the group would recommend making the appropriate revisions to the EOP-011-1 Standard.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	

Comment
We caution the use of "15-minute ACE recovery period" in the SAR. We believe the SDT should have clear direction to instead leverage the previously NERC Glossary-defined term, "Contingency Event Recovery Period." This term is referenced frequently within the standard and aligns with the efforts of the previous Standard Drafting Team.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SAR DT agrees that defined terms should be used within the standard.	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
In its comments to FERC's Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-7-000, Arizona Public Service Company (APS) outlined a proposal regarding notice to the RC when the extenuating conditions listed in Requirement R1.3.1 are met and the BA is unable to recover its ACE within the 15-minute recovery period. This proposal addressed FERC's concerns with extension of the 15-minute ACE recovery period, but also allowed appropriate flexibility to BAs when extenuating circumstances are present. (Order No. 835, P 36.) NorthWestern Energy agrees with the proposal that was outlined by APS in its comments to the FERC NOPR. (APS Comments, Accession No. 20160720-2146, Section II-A, pages 3–9.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider this information when developing modifications to the standard.	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. *Based on the scope of the SAR, do you have any other comments for drafting team consideration?*	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The IRC Standards Review Committee (SRC) provides these comments: As one of the “alternative modifications” the SRC proposes the SDT consider converting the Standard to a communication guide (developed under the auspices of the NERC OC) that could be converted to a standard if such a need were identified by the RCs.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT is unsure as to the issue you are raising. However, if you are proposing a communication guide instead of this SAR, the SAR DT believes that there is still clarity necessary to resolve the ambiguity highlighted in Requirement R1 Part 1.3.1 and to address the FERC order. In addition, the SAR DT will recommend to the NERC OC to review the existing Operating Reserve Management Guideline to ensure the communication issues are considered.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team evaluate the expansion of SAR that are associated with part 1.3.2 of the Standard. Our concern pertains to contingencies impacting frequency that is outside of the Responsible Entity's area that has a significant impact on the Responsible Entity meeting the 15 minute recovery.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of this SAR is explicitly and exclusively addressing the FERC Order directives. However, if you believe additional modifications are necessary, you may submit a SAR that addresses your concerns.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Duke Energy agrees that the SAR aligns with the directive from FERC, and also agrees with the scope of this project as written currently.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak appreciates the opportunity to provide comments on the BAL-002-2 SAR. Peak requests consideration be given to intended and/or unintended expectations resulting from the provision of the information to the Reliability Coordinator that may or may not be covered by additional NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands your concern and will recommend to the SDT that it consider potentially affected standards.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	

"The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns."

Since BAL-002-2 is addressing recovery from a **Reportable** Balancing Contingency Event (as distinct from a separately defined [non-reportable] Balancing Contingency Event), and since the FERC Order requires NERC to develop modifications regarding such **Reportable** events, in order to avoid any ambiguity or confusion we recommend that the SAR Objective be revised to state:

"The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a **Reportable** Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDTs are instructed to develop clear and unambiguous language in the standard and therefore, no modifications to the SAR are necessary.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	Yes
Document Name	

Comment

PacifiCorp is concerned that (1) the requirement 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, will be distracting requirements as the balancing area operators are working towards recovery in the 15-minute period. Setting aside recovering from the event to provide notification to the reliability coordinator could

impede efforts towards the recovery itself. We fail to see the value in these additional requirements and wonder if is this more suitable for the Eastern Interconnection – Western Interconnection power pool agencies are not 7x24 shops.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1 with respect to the responsible entity, the BA, communicating with the RC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In order to provide clear, unambiguous requirements to address the FERC directive, Texas RE recommends the standard drafting team (SDT) consider specifying a time-frame in which the notification and provision of a recovery plan is expected to occur. Developing a recovery plan and target recovery time may not be feasible within 15 minutes, so it may be more practical to require notification to the Reliability Coordinator (RC) within 15 minutes of the event, and provision of a recovery plan within an agreed upon time-frame.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider your comments while developing the language to address the directives from the FERC Order.	

End of Report

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, August 9, 2017.** 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 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

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 periodic 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 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (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."

The time commitment for this project 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 review and 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.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Standards affected: BAL-002-2

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 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:	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Supplemental Nomination Period Open through August 9, 2017

Now Available

Nominations are being sought for additional Standards Authorization Request drafting team members through **8 p.m. Eastern, Wednesday, August 9, 2017**. If you submitted a nomination during the initial nomination period (June 20 through July 3, 2017), you do not need to resubmit your nomination.

The nomination period is being reopened at the request of the Standards Committee (SC). There was considerable overlap in the nominations received for this project and Project 2017-01 Modifications to BAL-003-1.1. The SC requested the additional nomination period to 1) reduce the overlap between the two aforementioned projects; and, 2) increase the diversity within the two drafting teams.

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 Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The SC is expected to appoint members to the team September 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 Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-002-2 – Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event		
Date Submitted:			
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC Staff		
Telephone:	609.613.1848	Email:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated: "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with

SAR Information
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." Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 158 FERC ¶ 61,030 at P 37 (2017) ("FERC Order"). *See also, id.*, at P 2 and PP 35-36.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the standard, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address the FERC Order directives described above or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address either (A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or (B) proposing an equally efficient and effective alternative.

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

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.		Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.		Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.		Yes

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.

Regional Variances	
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. 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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. 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, 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. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-32

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-32.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that~~the Responsible Entity~~:

- is ~~a Balancing Authority~~ experiencing a Reliability Coordinator declared Energy Emergency Alert Level~~ or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level~~, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. 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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. 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, 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. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

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Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

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Unofficial Comment Form

Project 2017-06 Modifications to BAL-002-2

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2017-06 Modifications to BAL-002-2**. Comments must be submitted by **8 p.m. Eastern, Monday, May 7, 2018**.

Additional information is available on the project page. If you have questions, contact Principal Technical Advisor, Darrel Richardson (via email) or at (609) 613-1848.

Background

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (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."

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. Do you have any other comments for drafting team consideration?

   ☐ Yes
   ☐ No

   Comments:

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Rationales for BAL-002-3

February, 2018

Requirement R1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is a experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

Rationale R1

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller Balancing Authority's (BA) and Reserve Sharing Groups (RSG) in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

The language in R1 part 1.3 does not specifically state under which EEA level the exclusion applies to reduce the need for consequent modifications of the BAL-002 standard. Thus, language in Requirement 1 Part 1.3.1 addresses both current and future EEA process. In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event under

which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

In addition, to address FERC Order No. 835, the drafting team has modified Requirement R1 Part 1.3.1 to clarify that the Responsible Entity, is the Balancing Authority (BA) notifying the Reliability Coordinator (RC) of the conditions set forth in Requirement R1, Part 1.3.1 in accordance with the Energy Emergency Alert (EEA) procedures. Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert. Requirement R1 Part 1.3.1 requires the BA to provide additional information to the RC, allowing the RC to have a wide-area view of the state of the Bulk Electric System for possible future decisions concerning the System. It also provides for relief to a BA or RSG when reserves are being utilized under an EEA. These modifications keep the issues associated with Energy Emergencies within the Emergency Preparedness and Operations Standards, while allowing BAL-002-3 to compliment the process and clarify the narrow set of conditions where the BA and/or RSG is not subject to compliance to R1..

Requirement R2

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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Rationale R2

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Requirement R3

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, 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.

Rationale R3

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

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Standards Announcement

Reminder

Project 2017-06 Modifications to BAL-002-2

Initial Ballot and Non-binding Poll Open through May 7, 2018

Now Available

The initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** are open through **8 p.m. Eastern, Monday, May 7, 2018**.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience difficulties navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

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Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Comment Period Open through May 7, 2018

Now Available

A 45-day formal comment period for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Monday, May 7, 2018**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience difficulty navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 20, 2018.** Registered Ballot Body members can join the ballot pools here.

Next Steps

An initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 27 – May 7, 2018**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/133)
Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST
Voting Start Date: 4/27/2018 12:01:00 AM
Voting End Date: 5/8/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 189
Total Ballot Pool: 231
Quorum: 81.82
Weighted Segment Value: 69.46

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	54	1	28	0.8	7	0.2	0	11	8
Segment: 2	6	0.2	2	0.2	0	0	0	1	3
Segment: 3	50	1	19	0.655	10	0.345	0	10	11
Segment: 4	14	0.9	5	0.5	4	0.4	0	2	3
Segment: 5	54	1	25	0.676	12	0.324	0	9	8
Segment: 6	43	1	20	0.69	9	0.31	0	7	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	1	0	0	0	0	0	0	1	0
Segment: 10	7	0.4	3	0.3	1	0.1	0	2	1

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Totals:	231	5.5	102	3.821	43	1.679	0	44	42

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A
1	Exelon	Chris Scanlon		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Third-Party Comments
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Third-Party Comments

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Third-Party Comments
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Third-Party Comments
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Third-Party Comments
5	Westar Energy	Laura Cox		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Negative	Third-Party Comments
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 231 of 231 entries

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BALLOT RESULTS

Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 Non-binding Poll IN 1 NB
Voting Start Date: 4/27/2018 12:01:00 AM
Voting End Date: 5/8/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 176
Total Ballot Pool: 220
Quorum: 80
Weighted Segment Value: 77.19

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	50	1	24	0.857	4	0.143	14	8
Segment: 2	6	0.2	2	0.2	0	0	1	3
Segment: 3	50	1	16	0.696	7	0.304	15	12
Segment: 4	14	0.7	5	0.5	2	0.2	3	4
Segment: 5	50	1	22	0.733	8	0.267	12	8
Segment: 6	40	1	15	0.75	5	0.25	13	7
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	1	0	0	0	0	0	1	0
Segment: 9	1	0	0	0	0	0	1	0
Segment: 10	7	0.4	4	0.4	0	0	2	1
Totals:	220	5.3	88	4.136	26	1.164	62	44

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BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A
1	Exelon	Chris Scanlon		None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney	Dori Quam	None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry Bilke		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Laura Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	David Kiguel	David Kiguel		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 220 of 220 entries

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Comment Period Open through May 7, 2018

Now Available

A 45-day formal comment period for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Monday, May 7, 2018**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience difficulty navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 20, 2018.** Registered Ballot Body members can join the ballot pools here.

Next Steps

An initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 27 – May 7, 2018**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2017-06 Modifications to BAL-002-2 | BAL-002-3
Comment Period Start Date:	3/22/2018
Comment Period End Date:	5/8/2018
Associated Ballots:	2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST

There were 30 sets of responses, including comments from approximately 115 different people from approximately 87 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.

2. Do you have any other comments for drafting team consideration?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Cynthia Kneisl	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO
					Andy Fuhrman	Minnkota Power Cooperative	1	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE

PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.

Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed.

Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:

1. **The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)**
2. **The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).**

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

: FMPA is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO:

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time.”

Likes 0	
Dislikes 0	

Response

Richard Kinas - Orlando Utilities Commission - 5

Answer	No
Document Name	

Comment

OUC is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO:

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time.”

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No

Document Name	

Comment

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an EEA.

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create a CMEP Practice Guide that outlines an approach for ERO Compliance Staff to handle RBCEs during these situations.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) and provided an expected recovery time”.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

We believe that the conditions set forth in the first requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA’s time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment
Ameren believes that any Requirement for actions an entity is required to take when experiencing an RC declared EEA level belongs in EOP-011, Emergency Operations. **In lieu thereof, Ameren believes the following BAL-002-3 language would be an acceptable alternative to meet the intent and spirit of the FERC directive, until a revision of EOP-011-1 occurs as described below:** **In addition to the redline changes for R1.3 and R1.3.1, Ameren suggests adding the additional bullets as stated below:** **•provide updates to the ACE recovery plan, including target recovery time, to its Reliability Coordinator, during its communications with the RC as required in "Attachment 1-EOP-011-1 Energy Emergency Alerts"** **•and implements the ACE recovery plan when given an Operating Instruction to do so by its RC.**

Likes 0	
Dislikes 0	

Response

M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No
Document Name	

Comment
TVA believes that the conditions set forth in the 1st requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	

While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed.

Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:

1. The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)
2. The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. We believe the proposed reference to "preceding two bullet points" should be clarified, as compliance with this requirement can be confusing. Very few NERC Reliability Requirements identify an action and then follow that with an exemption to the action based on a specific condition. The proposed changes are made to the exemption portion of the requirement, which already implies that compliance with Requirement R1 part 1.1 is unnecessary. The embedded dual condition within the proposed bullet should be split to provide clarity. One bullet

should identify the inhibitive reasoning provided to the RC from the distressed BA or RSG that is unable to restore its ACE to the appropriate Pre
- The second bullet should also identify that the
ACE recovery plan was provided to the RC.

2. The reference to “recovery time” should be replaced with the appropriate NERC Glossary Term, Contingency Event Recovery Period.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

N/A to BHC

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA suggests rewording of “an ACE recovery plan” to “actions it will take to recover its ACE”. BPA believes this rewording will help R1 sound less like a defined term which will depend on or require additional documentation. BPA’s concern is that “an ACE recovery plan” will be assumed to be an additional document such as the Emergency Operating Plan.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

SRP supports the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	
Document Name	
Comment	
N/a	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The SDT may wish to clarify when the ACE recovery plan must be submitted for a BA to qualify for the exemption. The proposed BAL-002-3 R 1.3 now specifies that a BA may be exempt from BAL-002-3 R1.1 if it has “during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedure” notified the RC of conditions preventing it from responding and “provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.”	
Likes 0	

Dislikes 0	
Response	

2. Do you have any other comments for drafting team consideration?	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment
TVA believes that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment
The SPP Standards Review Group suggests that the drafting team provide clarity on the intent of the proposed language pertaining to Requirement R1 Part 1.3.1. The proposed language in BAL-002 (Part 1.3.1) is addressing entities that would be in an EEA 3 knowing that they wouldn't return to an acceptable status in the required 15 minutes. Looking at EOP-011, any entity that is in an EEA 3 per Attachment 1, that entity would have to report their status to the Reliability Coordinator (RC) every hour. To our understanding, the entity being identified in BAL-002 (Part 1.3.1-which would be in an EEA 3 situation and would not be in compliance) could make their report in that same hour until they return to an acceptable status. We ask the drafting team to clarify whether there is connection between the required actions of these two standards. If the drafting team agrees with our understanding, we would suggest that the drafting team include some language discussing the connection of both standards in BAL-002-3. This would provide clarity on the expectations of entities that don't recover in the required 15 minutes as well as being in an EEA 3 condition.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment

We believe that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002.

The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Dominion Energy has a concern regarding the Technical Rationale document. It appears that SDT has transitioned the existing GTB document to a Technical Rationale document without completely addressing all of the compliance langugae contained in the document.

"Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability."

This first example states when an entity does not have to comply and the standard is not applicable. It is not intent, it is a statement that directly impacts compliance. While the latter section of the section does state what the intent of the SDT was when developing the language and, in isolation would be appropriate for the TR document, the former part of the statement is not appropriate for the TR document. Just because a statement is not a specific example of how to comply does not render it appropriate for the TR document.

"In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event underwhich its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance."

The second quotation also makes a specific compliance statement, exempting a specific entity from compliance of the Requirement. While not an 'example' that could be directly ported to an IG document, it is compliance language that is not appropriate for a TR document. As stated before, just because compliance language does not fit the definition of IG does not render it appropriate for TR.

"Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert."

The third quotation is a statement that clearly states how to comply with the EEA process. Once again, while not specific IG that statement is not appropriate for a TR document.

Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). Under these situations the BA may likely need to perform dozens of tasks in a 15 minute period.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The original Disturbance Control Standard (DCS) in Policy 1 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
- Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

- Recover from Reportable Balancing Contingency Events in 15 minutes.
- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.
- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

The redline change to the standard has the BA telling the RC something they both already know and also expects the BA during an emergency to specifically mention two bullets in the standard. It should also be noted that the requirement is basically duplicative of EOP-011 R2.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	

Dislikes 0	
Response	
Richard Kinas - Orlando Utilities Commission - 5	
Answer	Yes
Document Name	
Comment	

OUC is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states “Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;”. Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. OUC agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA’s ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot’s proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

Recover from large events less than or equal to MSSC in 15 minutes.

Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	

Comment

FMPA is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states "Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;". Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. FMPA agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

{C}· Recover from large events less than or equal to MSSC in 15 minutes.

{C}· Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates suggests that NERC post a complete redline of Proposed Reliability Standard BAL-002-3 to ensure the industry is fully aware of the transition of the Supplemental Material to a Technical Rationale document. The Redline to Last Approved Version of Proposed Reliability Standard BAL-002-3 posted to the NERC project page on March 22, 2018 is not a complete redline as it does not show the removal of the "Supplemental Material" (also known as Technical Rationale), which is currently included in the effective version BAL-002-2(i).

Furthermore, the document entitled "Rationales for BAL-002-3" should be entitled "Technical Rationale for BAL-002-3" in accordance with the NERC Technical Rationale for Reliability Standards Policy, and a redline to the last version of this document approved by industry should also be posted.

Additionally, the document entitled "Rationales for BAL-002-3" seems to include implementation guidance as it states "Requirement R1 does not apply when…".

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

- Assess the incoming alarms and determine the extent of the problem.
- Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.
- Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.
- Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
- Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

- Recover from Reportable Balancing Contingency Events in 15 minutes.
- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.
- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

Since it is necessary for a Balancing Authority to be in the conditions described in the first three bullets and have communicated those conditions to their Reliability Coordinator in order to be declared in an EEA, it is not necessary to repeat those steps in the proposed language in the fourth bullet of 1.3.1. The resulting fourth bullet would then read "has provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

It appears that this version needs some clean-up prior to the final version. Texas RE noticed the following:

- The grammatical structure of Requirement 1 Part 1.3 is unclear as to whether the bullets are just for the RSG or the BA as well.
- In the “Rationales” document there is a reference to changes in definition of Contingency Reserve “in the posting” but it does not specify which posting.
- Texas RE requests to see a draft updated CR Form 1 since it is an associated document in Section F of the standard. Will this form be housed with the related documents?

Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2017-06 Modifications to BAL-002-2 | BAL-002-3
Comment Period Start Date:	3/22/2018
Comment Period End Date:	5/8/2018
Associated Ballot:	2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST

There were 30 sets of responses, including comments from approximately 115 different people from approximately 87 companies representing the 10 Industry Segments as shown in the table on the following pages.

The Standard Drafting Team (SDT) scope was to address FERC's (Commission) requirements as listed in Order No. 835. The Commission stated in Order No. 835 it was concerned with a Balancing Authority operating out-of-balance for an extended period of time and is "leaning on the system" by relying on external resources to meet its obligations. Therefore, the Commission directed NERC to develop modifications to BAL-002-2 Requirement 1 to require balancing authorities: (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 the ACE recovery plan, including a target recovery time. The SDT took careful consideration to assure that fulfillment of this requirement could occur during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures.

Requirement R1, Part 1.3 addresses qualifying for exemption from Requirement R1 Part 1.1 and all conditions listed in Requirement R1, Part 1.3.1 must be met in order to qualify for the exemption. One of the conditions, is the BA is experiencing a Reliability Coordinator declared Energy Emergency Alert (EEA) Level. When a BA is experiencing a declared Energy emergency Alert level, it is communicating with its RC the conditions and its expected time to recover, which is basically addressing when a BA is out-of-balance and is "leaning on the

system". By requiring an ACE recovery plan, the BA is providing the RC its expected time to recover and would no longer experiencing an EEA.

The SDT did not believe providing an ACE recovery plan place an onerous requirement on the BA, since under an EEA it requires the BA to provide to the RC such information.

Finally, to restate Requirement R1, Part 1.3 addresses qualifying for exemption from Requirement R1 Part 1.1. Since all conditions of Requirement R1, Part 1.3.1 must be met in order to qualify for exemption, the SDT expects exemption to be very rare. However, for the Responsible Entity to qualify for exemption, it must meet all conditions:

the Responsible Entity: is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures: (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1 , and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.**

2. **Do you have any other comments for drafting team consideration?**

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Cynthia Kneisl	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Andy Fuhrman	Minnkota Power Cooperative	1	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						and Energy Marketing		
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. *The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision*.

Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions. With regards to your comment concerning event analysis the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed. **Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:** 1. **The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)** 2. **The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).** **Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA**	

and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE. **We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
: FMPA is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO: While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.	

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA). The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions. With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Richard Kinas - Orlando Utilities Commission - 5	
Answer	No
Document Name	

Comment
OUC is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO: While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA). The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time.”
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions.	

With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an EEA. The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create a CMEP Practice Guide that outlines an approach for ERO Compliance Staff to handle RBCEs during these situations. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) and provided an expected recovery time”.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions. With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We believe that the conditions set forth in the first requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren believes that any Requirement for actions an entity is required to take when experiencing an RC declared EEA level belongs in EOP-011, Emergency Operations. **In lieu thereof, Ameren believes the following BAL-002-3 language would be an acceptable alternative to meet the intent and spirit of the FERC directive, until a revision of EOP-011-1 occurs as described below:** **In addition to the redline changes for R1.3 and R1.3.1, Ameren suggests adding the additional bullets as stated below:** **•provide updates to the ACE recovery plan, including target recovery time, to its Reliability Coordinator, during its communications with the RC as required in "Attachment 1-EOP-011-1 Energy Emergency Alerts"** **•and implements the ACE recovery plan when given an Operating Instruction to do so by its RC.**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT scope was associated with only the FERC Order associated with BAL-002. This SDT is not able to change the EEA procedure which would require a new or revised SAR. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No

Document Name	
Comment	
TVA believes that the conditions set forth in the 1st requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed. Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:	

1. The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)

2. The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment	
1. We believe the proposed reference to “preceding two bullet points” should be clarified, as compliance with this requirement can be confusing. Very few NERC Reliability Requirements identify an action and then follow that with an exemption to the action based on a specific condition. The proposed changes are made to the exemption portion of the requirement, which already implies that compliance with Requirement R1 part 1.1 is unnecessary. The embedded dual condition within the proposed bullet should be split to provide clarity. One bullet should identify the inhibitive reasoning provided to the RC from the distressed BA or RSG that is unable to restore its ACE to the appropriate Pre-Reporting Contingency Event ACE Value within the Contingency Event Recovery Period. The second bullet should also identify that the ACE recovery plan was provided to the RC. 2. The reference to “recovery time” should be replaced with the appropriate NERC Glossary Term, Contingency Event Recovery Period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. An entity must meet all of the specified conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption. With respect to your suggestion to split the fourth bullet, the SDT believes the condition as written must be a single bullet to maintain continuity within the bullet. Recovery time is an undefined term when dealing with the exemption and is variable when dealing with individual ACE recovery plans.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
N/A to BHC	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA suggests rewording of “an ACE recovery plan” to “actions it will take to recover its ACE”. BPA believes this rewording will help R1 sound less like a defined term which will depend on or require additional documentation. BPA’s concern is that “an ACE recovery plan” will be assumed to be an additional document such as the Emergency Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The SDT took the wording directly from the FERC order.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the proposed revisions.	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	
Document Name	
Comment	
N/a	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The SDT may wish to clarify when the ACE recovery plan must be submitted for a BA to qualify for the exemption. The proposed BAL-002-3 R 1.3 now specifies that a BA may be exempt from BAL-002-3 R1.1 if it has "during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedure" notified the RC of conditions preventing it from responding and "provided the Reliability Coordinator with an ACE recovery plan, including target recovery time."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the entire recovery time frame is the period in which the BA is to notify the RC of its ACE recovery plan. During your discussions with the RC to declare an EEA the BA must provide all information associated with the	

emergency including the estimated period of the potential EEA and must update the RC hourly or upon a change of EEA status until the EEA is terminated. Part of the discussion with the RC to qualify for the exemption under BAL-002 will include your ACE recovery plan and the target recovery time. An entity must meet all of the specified conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.

2. *Do you have any other comments for drafting team consideration?*	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment
TVA believes that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment
The SPP Standards Review Group suggests that the drafting team provide clarity on the intent of the proposed language pertaining to Requirement R1 Part 1.3.1. The proposed language in BAL-002 (Part 1.3.1) is addressing entities that would be in an EEA 3 knowing that

they wouldn't return to an acceptable status in the required 15 minutes. Looking at EOP-011, any entity that is in an EEA 3 per Attachment 1, that entity would have to report their status to the Reliability Coordinator (RC) every hour. To our understanding, the entity being identified in BAL-002 (Part 1.3.1-which would be in an EEA 3 situation and would not be in compliance) could make their report in that same hour until they return to an acceptable status. We ask the drafting team to clarify whether there is connection between the required actions of these two standards. If the drafting team agrees with our understanding, we would suggest that the drafting team include some language discussing the connection of both standards in BAL-002-3. This would provide clarity on the expectations of entities that don't recover in the required 15 minutes as well as being in an EEA 3 condition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
We believe that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its	

imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy has a concern regarding the Technical Rationale document. It appears that SDT has transitioned the existing GTB document to a Technical Rationale document without completely addressing all of the compliance langugae contained in the document. "Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability." This first example states when an entity does not have to comply and the standard is not applicable. It is not intent, it is a statement that directly impacts compliance. While the latter section of the section does state what the intent of the SDT was when developing the	

language and, in isolation would be appropriate for the TR document, the former part of the statement is not appropriate for the TR document. Just because a statement is not a specific example of how to comply does not render it appropriate for the TR document. "In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event underwhich its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance." The second quotation also makes a specific compliance statement, exempting a specific entity from compliance of the Requirement. While not an 'example' that could be directly ported to an IG document, it is compliance language that is not appropriate for a TR document. As stated before, just because compliance language does not fit the definition of IG does not render it appropriate for TR. "Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert." The third quotation is a statement that clearly states how to comply with the EEA process. Once again, while not specific IG that statement is not appropriate for a TR document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider your comments and make associated modifications, if necessary.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.	

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). Under these situations the BA may likely need to perform dozens of tasks in a 15 minute period.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The original Disturbance Control Standard (DCS) in Policy 1 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
- Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

- Recover from Reportable Balancing Contingency Events in 15 minutes.
- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.
- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

The redline change to the standard has the BA telling the RC something they both already know and also expects the BA during an emergency to specifically mention two bullets in the standard. It should also be noted that the requirement is basically duplicative of EOP-011 R2. As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.	
Richard Kinas - Orlando Utilities Commission - 5	
Answer	Yes
Document Name	
Comment	
OUC is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states "Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;". Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. OUC agrees with the following comments submitted by MRO:	

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

Recover from large events less than or equal to MSSC in 15 minutes.

Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

FMPA is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states "Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;". Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. FMPA agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

{C}· Recover from large events less than or equal to MSSC in 15 minutes.

{C}· Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events. Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies. As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates suggests that NERC post a complete redline of Proposed Reliability Standard BAL-002-3 to ensure the industry is fully aware of the transition of the Supplemental Material to a Technical Rationale document. The Redline to Last Approved Version of Proposed Reliability Standard BAL-002-3 posted to the NERC project page on March 22, 2018 is not a complete redline as it does not show the removal of the "Supplemental Material" (also known as Technical Rationale), which is currently included in the effective version BAL-002-2(i).	

Furthermore, the document entitled “Rationales for BAL-002-3” should be entitled “Technical Rationale for BAL-002-3” in accordance with the NERC Technical Rationale for Reliability Standards Policy, and a redline to the last version of this document approved by industry should also be posted. Additionally, the document entitled “Rationales for BAL-002-3” seems to include implementation guidance as it states “Requirement R1 does not apply when…”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will pass your comment on the the appropriate NERC staff.	
Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages. One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA’s ACE is negatively impacting frequency or transmission limits. The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to: • Assess the incoming alarms and determine the extent of the problem. • Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.	

- Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.
- Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
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There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

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- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

Since it is necessary for a Balancing Authority to be in the conditions described in the first three bullets and have communicated those conditions to their Reliability Coordinator in order to be declared in an EEA, it is not necessary to repeat those steps in the proposed language in the fourth bullet of 1.3.1. The resulting fourth bullet would then read "has provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

It appears that this version needs some clean-up prior to the final version. Texas RE noticed the following:

- The grammatical structure of Requirement 1 Part 1.3 is unclear as to whether the bullets are just for the RSG or the BA as well.
- In the "Rationales" document there is a reference to changes in definition of Contingency Reserve "in the posting" but it does not specify which posting.
- Texas RE requests to see a draft updated CR Form 1 since it is an associated document in Section F of the standard. Will this form be housed with the related documents?

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the current language provides sufficient clarity.	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. 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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. 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, 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. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
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1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-32

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-32.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

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1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

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R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Final Ballot Open through July 16, 2018

Now Available

The final ballot for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** is open through **8 p.m. Eastern, Monday, July 16, 2018**.

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience difficulty navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 FN 2 ST
Voting Start Date: 7/5/2018 9:17:46 AM
Voting End Date: 7/16/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 195
Total Ballot Pool: 231
Quorum: 84.42
Weighted Segment Value: 71.85

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	54	1	30	0.789	8	0.211	0	10	6
Segment: 2	6	0.4	2	0.2	2	0.2	0	1	1
Segment: 3	50	1	20	0.667	10	0.333	0	10	10
Segment: 4	14	0.9	6	0.6	3	0.3	0	2	3
Segment: 5	54	1	26	0.703	11	0.297	0	9	8
Segment: 6	43	1	21	0.724	8	0.276	0	7	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	1	0.1	1	0.1	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Totals:	231	6.1	112	4.383	43	1.717	0	40	36

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	N/A
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Thomas Savin	Shelly Dineen	Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 231 of 231 entries

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Exhibit E

Rationale for BAL-002-3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationales for BAL-002-3

February, 2018

Requirement R1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is a experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- 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.

Rationale R1

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller Balancing Authority's (BA) and Reserve Sharing Groups (RSG) in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

The language in R1 part 1.3 does not specifically state under which EEA level the exclusion applies to reduce the need for consequent modifications of the BAL-002 standard. Thus, language in Requirement 1 Part 1.3.1 addresses both current and future EEA process. In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event under

which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

In addition, to address FERC Order No. 835, the drafting team has modified Requirement R1 Part 1.3.1 to clarify that the Responsible Entity, is the Balancing Authority (BA) notifying the Reliability Coordinator (RC) of the conditions set forth in Requirement R1, Part 1.3.1 in accordance with the Energy Emergency Alert (EEA) procedures. Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert. Requirement R1 Part 1.3.1 requires the BA to provide additional information to the RC, allowing the RC to have a wide-area view of the state of the Bulk Electric System for possible future decisions concerning the System. It also provides for relief to a BA or RSG when reserves are being utilized under an EEA. These modifications keep the issues associated with Energy Emergencies within the Emergency Preparedness and Operations Standards, while allowing BAL-002-3 to compliment the process and clarify the narrow set of conditions where the BA and/or RSG is not subject to compliance to R1..

Requirement R2

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 make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Rationale R2

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Requirement R3

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, 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.

Rationale R3

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

Exhibit F

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2017-06 Modifications to BAL-002-2

	Name	Entity
Chair	Jerry Rust	Northwest Power Pool
Co-Chair	Glenn Stephens	Santee Cooper
Members	Gerry Beckerle	Ameren
	Natika Mago	Electric Reliability Council of Texas
	Mark Prosperi-Porta	BC Hydro
	Lonnie L Lindekugel	Southwest Power Pool
	David Kimmel	PJM Interconnection
	Sean Erickson	WAPA
NERC Staff	Darrel Richardson	North American Electric Reliability Corporation
	Robert Cummings	North American Electric Reliability Corporation
	Brad Gordon	North American Electric Reliability Corporation
	Candice Castaneda	North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM18-8-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULE MAKING

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July 23, 2018

TABLE OF CONTENTS

I. BACKGROUND 3
II. COMMENTS 5
A. Corrective Action Plans for Supplemental GMD Vulnerability Assessments 6
1. NOPR 6
2. Comments 7
B. Extending Corrective Action Plan Deadlines 18
1. NOPR 18
2. Comments 20
III. Conclusion 23

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM18-8-000**

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 Notice of Proposed Rulemaking ("NOPR") regarding proposed Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in this proceeding on May 17, 2018.[1] NERC provides these comments as the Commission-certified electric reliability organization responsible for the development and enforcement of mandatory Reliability Standards, including proposed Reliability Standard TPL-007-2.[2]

In the NOPR, the Commission proposes to approve proposed Reliability Standard TPL-007-2, as well as the associated implementation plan, Violation Risk Factors, and Violation Severity Levels. The Commission, however, proposes to direct NERC to revise the standard to require entities to develop Corrective Action Plans to address vulnerabilities identified through supplemental Geomagnetic Disturbance ("GMD") Vulnerability Assessments. In addition, the

[1] Notice of Proposed Rulemaking, *Geomagnetic Disturbance Reliability Standard*, 163 FERC ¶ 61,126 (2018) ("NOPR").

[2] The Commission certified NERC as the electric reliability organization ("ERO") in 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007), *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

Commission sets forth two possible proposals regarding proposed TPL-007-2 Requirement R7 Part 7.4, which relates to the circumstances under which an entity may extend Corrective Action Plan deadlines.

NERC supports the Commission's proposal to approve Reliability Standard TPL-007-2. The proposed standard raises the bar for reliability. It provides a flexible process for maintaining timeliness and accountability in the development and completion of Corrective Action Plans to mitigate identified GMD vulnerabilities. Further, the proposed standard addresses the Commission's directives from Order No. 830[3] to account for the localized peak effects of GMDs in planning studies.

As discussed in its Petition,[4] NERC's approach to accounting for localized peak effects of GMD is sound and reasonable based on currently-available information. Research is currently underway under NERC's GMD Research Work Plan to improve understanding of the characteristics and spatial scales of localized peak GMD effects.[5] To ensure that NERC's GMD Reliability Standard continues to reflect the best available information, NERC commits to initiate a review of TPL-007-2 following the completion of the work plan. As the research work described in NERC's GMD Research Work Plan is directly relevant to the standard modification proposals discussed in the NOPR, NERC encourages the Commission to allow NERC to complete this work and its subsequent review prior to issuing any further standard modification directives.

---

3 *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215 (2016), *reh'g denied*, 158 FERC ¶ 61,041 (2017) ("Order No. 830").

4 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard TPL-007-2*, Docket No. RM18-8-000 (filed Jan. 22, 2018) ("Petition").

5 *See Revised Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation*, Docket No. RM15-11-003 (filed Apr. 19, 2018) ("GMD Research Work Plan").

For these reasons, which are explained more fully herein, NERC respectfully requests that the Commission approve Reliability Standard TPL-007-2 as proposed by NERC.

I. BACKGROUND

On January 22, 2018, NERC filed proposed Reliability Standard TPL-007-2 for Commission approval. The proposed standard was developed in response to the Commission's directives from Order No. 830, in which the Commission approved currently-effective Reliability Standard TPL-007-1. As explained in further detail in NERC's Petition, the proposed standard improves upon the currently-effective version of the standard and addresses the Commission's directives from Order No. 830 by:

- requiring entities to assess their vulnerabilities to the supplemental GMD event, a second defined event that accounts for the localized peak effects of severe GMD events and which is not based solely on spatially-averaged data;[6]
- requiring entities to perform supplemental thermal impact assessments of applicable power transformers based on geomagnetically-induced current ("GIC") information for the supplemental GMD event;[7]
- requiring entities to implement process(es) to obtain GIC monitor and magnetometer data;[8] and
- requiring entities to meet requirements for timeliness and accountability in implementing

[6] *See* Order No. 830 at P 44 ("[T]he Commission . . . 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.") and P 47 ("Without pre-judging how NERC proposes to address the Commission's directive, NERC's response . . . 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.").

[7] *See id.* at P 65 ("[T]he 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.").

[8] *See id.* at P 88 (directing NERC to modify TPL-007-1 "to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness"). Additionally, the Commission directed NERC to collect GIC monitoring and magnetometer data from entities for the period beginning May 2013 going forward, and to make that information available. *Id.* at P 89.

Corrective Action Plans for addressing identified benchmark GMD vulnerabilities.[9]

Like its predecessor version TPL-007-1, the proposed standard is based on the latest in scientific and technical understanding of severe GMD events and the potential risks these events may pose to reliability.

Since completing development of the proposed standard, NERC has continued its work on GMD issues. On April 19, 2018, NERC filed a revised GMD Research Work Plan with the Commission.[10] This plan provides a detailed framework for researching the specific GMD areas of concern noted by the Commission in Order No. 830. Later this year, NERC anticipates issuing a request to registered entities for GMD monitoring data under its authority in Section 1600 of the NERC Rules of Procedure.[11] These projects are expected to increase understanding of GMDs and provide useful information for continued evaluation of the technical aspects underpinning the proposed standard. To take advantage of these insights, NERC will initiate a formal review of the proposed TPL-007-2 standard following the conclusion of the GMD Research Work Plan. The purpose of this review will be to ensure that the GMD planning standard and the underlying GMD planning events are supported by the latest in scientific and technical understanding, identify any adjustments or refinements that may be necessary, and account for any other considerations that arise during the course of implementing the TPL-007 standard.

On May 17, 2018, the Commission issued a NOPR proposing to approve Reliability Standard TPL-007-2. In the NOPR, the Commission also proposes to direct NERC to modify the

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[9] *See id.* at PP 101-102 (directing NERC to modify TPL-007-1 to include a one-year deadline for the development of any required Corrective Action Plans, a two-year deadline to complete the implementation of non-hardware mitigation, and a four-year deadline to complete the implementation of hardware mitigation).

[10] GMD Research Work Plan, *supra* note 5.

[11] The NERC Rules of Procedure ("NERC ROP") are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

standard's requirements for Corrective Action Plans. Specifically, the Commission proposes to direct NERC to modify the standard "to require applicable entities to develop and implement corrective action plans to mitigate supplemental GMD event vulnerabilities."[12] With respect to proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.4, which relates to extension of Corrective Action Plan deadlines, the Commission proposes adopting one of two possible proposals. Under the first option, the Commission proposes to direct NERC to modify the standard to require "NERC and the Regional Entities, as appropriate, consider requests for extension of time [to complete Corrective Action Plan activities] on a case-by-case basis."[13] NERC would also be directed to prepare and submit a report regarding the circumstances under which such requests have been made and NERC's disposition of such requests. Under the second option, the Commission would approve TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC and would direct NERC to submit a report on the use of the provision.[14] The Commission seeks comments on its proposals.

II. COMMENTS

NERC supports the Commission's proposal to approve Reliability Standard TPL-007-2. Proposed Reliability Standard TPL-007-2 addresses the Commission's directives as set forth in Order No. 830 and represents another milestone in NERC's efforts to harden the grid against the potential reliability risks posed by severe GMD events, including the risks posed by severe,

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12 NOPR at P 24.

13 *Id*. at P 50.

14 *Id*. at P 51.

localized effects. NERC does not, however, support the Commission's proposals to further modify the standard.

As discussed below, the proposed standard provides strong protections against the potential reliability risks of a severe GMD event and provides a reasonable approach for mitigating vulnerabilities identified through the benchmark and supplemental GMD Vulnerability Assessments. NERC, therefore, does not support the Commission's first standard modification proposal, which is to direct NERC to modify the standard to require entities to develop Corrective Action Plans to address vulnerabilities identified through supplemental GMD Vulnerability Assessments. With respect to the second set of proposals regarding TPL-007-2 Requirement R7 Part 7.4, NERC supports the second option described by the Commission, which would be to approve the provision as proposed by NERC. As described herein, the proposed provision helps to ensure timely mitigation of GMD vulnerabilities in accordance with Order No. 830 while accounting for the circumstances under which Corrective Action Plan deadlines cannot be met. NERC provides the following comments on the proposals discussed in the NOPR.

A. Corrective Action Plans for Supplemental GMD Vulnerability Assessments

1. NOPR

In the NOPR, the Commission stated that proposed Reliability Standard TPL-007-2 addresses the Commission's directive in Order No. 830 in that it requires entities to assess their systems' vulnerabilities to the supplemental GMD event, a second planning event that is not based solely on spatially-averaged data and which is intended to capture the localized peak effects of GMDs.[15] The Commission, however, expresses concern that the proposed standard

[15] *Id*. at PP 23-24.

does not require entities to develop and implement a formal Corrective Action Plan to mitigate such vulnerabilities.[16] Specifically, the Commission stated:

> Moreover, in Order No. 830, 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." NERC's proposal to modify the benchmark, but then allow applicable entities the discretion to take corrective action based solely on the results of the spatially-averaged benchmark analysis while taking under advisement ("an evaluation of possible actions") the results of the supplemental assessment, does not satisfy the clear intent of the Commission's directive.[17]

While expressing support for the technical basis underlying the proposed supplemental GMD event, the Commission nevertheless expresses skepticism regarding NERC's assertion that requiring mandatory Corrective Action Plans would be premature at this time.[18] The Commission therefore proposes to direct NERC to modify proposed Reliability Standard TPL-007-2 to establish requirements for entities to develop and complete Corrective Action Plans for vulnerabilities identified through supplemental GMD Vulnerability Assessments.[19] The Commission proposes to direct NERC to file the revised standard within 12 months of the effective date of Reliability Standard TPL-007-2.

2. Comments

NERC supports the Commission's proposal to approve the proposed standard and the new supplemental GMD event. As the Commission states in the NOPR, the proposed

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16 *Id*. at P 24. Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.3 provides that, if the analysis concludes there is Cascading caused by the event, the entity shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

17 *Id*. at P 33 (internal citation omitted).

18 *See id*. at PP 35-39.

19 *Id*. at P 24.

supplemental GMD event builds on the same framework as the approved benchmark GMD event, but with some modifications to account for localized peak effects of GMDs. The proposed standard offers a reasonable approach for meeting the Commission's Order No. 830 directive to develop a GMD planning event that is not based solely on spatially-averaged data. NERC, however, has several concerns regarding the basis for the Commission's proposal to require entities to develop and implement formal Corrective Action Plans for vulnerabilities identified through GMD Vulnerability Assessments based on the supplemental GMD event. For these reasons, which are explained below, NERC does not support the Commission's NOPR proposal to modify the standard. NERC respectfully requests that the Commission accept NERC's commitment to conduct a formal review of the standard following the completion of the GMD Research Work Plan in lieu of including any standard modification directives in a final rule in this proceeding.

a) As Proposed, Reliability Standard TPL-007-2 Provides Strong Protection against the Reliability Risks of GMDs

Proposed Reliability Standard TPL-007-2 provides strong protection against the potential system-wide impacts of a severe GMD event consistent with both Order No. 779[20] and Order No. 830.[21] The proposed standard requires entities to assess their vulnerabilities using two defined GMD planning events intended to model the system-wide and potential localized impacts of a severe GMD storm. Using the approved benchmark GMD event, entities will

[20] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013) (directing NERC to develop one or more Reliability Standard "that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole"); *and* Order No. 830 at P 44 (approving Reliability Standard TPL-007-1, but directing NERC to revise the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data).

[21] Order No. 830 at P 44.

identify the potential system-wide impacts of a severe, 1-in-100 year GMD event. The proposed supplemental GMD event is intended to "supplement" the benchmark GMD event by providing a means to evaluate localized enhancements of a geomagnetic field during a severe GMD event that could potentially affect the reliable operation of the Bulk-Power System. It has been observed that severe GMD events may include peak geomagnetic fields of limited duration in a given local area, which decrease in intensity over distance.[22] The associated impacts could include increased reactive power loss and hot spot heating in some power transformers or voltage depressions in a local area.

If vulnerabilities are identified through either one of these assessments, entities are required to take action. Entities must develop Corrective Action Plans if their studies based on the benchmark GMD event identify potential voltage collapse, Cascading, or uncontrolled islanding. Under proposed Reliability Standard TPL-007-2, entities would be required to implement their selected mitigation measures on the timeline provided by the Commission in Order No. 830. If an entity determines, through its supplemental GMD Vulnerability Assessment, that a severe GMD event with localized enhancements of the geomagnetic field could impact a selected location and cause Cascading, then the entity's supplemental GMD Vulnerability Assessment must include an evaluation of "possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s)."[23] This evaluation is not merely advisory, but rather supports a range of potential mitigating actions, such as additional hardware mitigation, operating procedures, or other resilience actions to enhance recovery and restoration.

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22 *See* Petition, Ex. I (Supplemental GMD Event Description White Paper) at 8.

23 Petition, Attachment A, Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.3.

Furthermore, some of the mitigating actions identified through this evaluation would directly support mitigation that is required by other NERC Reliability Standards. Proposed Reliability Standard TPL-007-2 Requirement R8 Part 8.4 would require each applicable planning entity to convey information from its GMD planning studies to its Reliability Coordinator. Reliability Standard EOP-010-1 Requirement R1 Part 1.1 requires the Reliability Coordinator to implement GMD Operating Plans that include "activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area."[24] Such activities could include posturing the system to minimize GIC flows or tolerate increased reactive power losses, increasing operator situational awareness to respond to abnormal conditions, or preparing emergency or restoration plans for effective restoration following the event.[25] A supplemental GMD Vulnerability Assessment could, for example, identify load shedding plans that would prevent Cascading or identify additional at-risk transformers not identified through the benchmark GMD Vulnerability Assessment that should be protected with operating measures during a severe GMD event with localized peak geoelectric fields. The proposed standard would thus require the exchange of information to support the development of GMD Operating Plans that are based on detailed system studies and risk analysis.

Taken together, the GMD Vulnerability Assessments and Corrective Action Plans required by TPL-007-2 and the Operating Procedure requirements contained in EOP-010-1 provide a layered and effective approach to addressing the risks from severe GMD events. Given

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[24] Reliability Standard EOP-010-1 Requirement R1 Part 1.1, https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-010-1.pdf.

[25] Examples of possible actions to include in Operating Procedures are described in the NERC GMD Task Force Phase 2, Operating Procedure Template (Jan. 16, 2013), https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMDTF_Phase_2-Operating_Procedure_Template-Transmission%20Generation.pdf.

the relationship between the supplemental and benchmark GMD events, NERC anticipates that that Corrective Action Plans, when needed to address performance requirements for the benchmark GMD event, will also provide a large degree of protection to the Bulk-Power System for events with locally-enhanced geomagnetic fields. Operating Procedures based on analysis of the supplemental GMD event would help prepare operators for specific localized effects of severe GMD events that have the potential to impact the reliable operation of the Bulk-Power System.

In summary, the proposed standard provides a conservative and rigorous approach for assessing the known characteristics of a severe GMD event on the reliable operation of the Bulk-Power System and for taking appropriate measures to mitigate the effects of such an event. NERC believes that the proposed standard addresses the Commission's concerns from Order No. 779 and Order No. 830, and requests that the standard be approved without modification.

b) The Proposed Standard Provides a Reasonable Approach for Addressing Extreme Localized GMD Peak Effects

As described in the previous section, proposed Reliability Standard TPL-007-2 provides strong protection against the potential reliability risks of severe GMD events, consistent with both Order No. 779 and Order No. 830. The Commission has nevertheless expressed concern in the NOPR with NERC's proposed approach for addressing vulnerabilities to the supplemental GMD event. NERC maintains that the standard provides a reasonable approach for evaluating and mitigating the potential reliability impacts of peak GMD effects. This approach is based on, and accounts for limitations in, the current state of scientific and technical knowledge.

NERC is concerned that the Commission's proposal to require the development and implementation of Corrective Action Plans for the supplemental GMD Vulnerability Assessment would result in the *de facto* replacement of the benchmark GMD event with the proposed

supplemental GMD event. The proposed supplemental GMD event was neither developed nor intended to replace the benchmark GMD event in this manner. Further, should the proposed supplemental GMD event be applied to an overly-large area, it would represent an event significantly more extreme than a 1-in-100 year GMD event. Unlike the benchmark GMD event, which is intended to represent the impacts of a 1-in-100 year storm on the Bulk-Power System, the supplemental GMD event is meant solely to simulate the impacts from an extreme localized GMD effect if local turbulent solar activity amplifies the local voltages centered on a particular select area identified by the planner. There are several reasons why replacing the benchmark GMD event for the proposed supplemental GMD event would not promote prudent, cost-effective, risk-based system planning. In light of these concerns, which are described more fully below, NERC does not support the Commission's proposed directive. NERC maintains that the better approach would be to continue the scientific and engineering evaluation of geoelectric field enhancements, as outlined in the GMD Research Plan and further described below, before considering further revisions to the mandatory and enforceable requirements in the TPL-007 standard.

Proposed Reliability Standard TPL-007-2 carries forward the approach of approved Reliability Standard TPL-007-1 of requiring entities to assess their vulnerabilities to the benchmark GMD event and to develop and implement Corrective Action Plans to address identified system vulnerabilities. Since its development, the approved benchmark GMD event remains strongly supported as representative of a severe 1-in-100 year GMD event for assessing impacts on the Bulk-Power System.[26] The proposed supplemental GMD event can be thought of

[26] Since NERC filed its petition for approval of TPL-007-1 and the benchmark GMD event in 2014 in Docket No. RM15-11-000, similar extreme value analysis of magnetometer data has been performed by researchers at the Geomagnetic Laboratory, Natural Resources Canada. This analysis affirms the selection of the peak geoelectric field

as the benchmark GMD event, but with an amplified magnetic field in a localized area and with a finite time duration to simulate extreme localized GMD effects. It was developed, in response to Order No. 830, to provide a means to model the type of localized enhancement observed during some severe GMD events. An entity's supplemental GMD Vulnerability Assessment would be similar to its benchmark GMD Vulnerability Assessment, but it would employ a higher peak geoelectric field in all or part of the area studied, depending on the size of the enhanced area that the entity assumes and the modeling capabilities and approach it employs. While the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis for requiring Corrective Action Plans.

Specifically, while the geoelectric field magnitudes for both the benchmark and supplemental GMD events are rigorously defined using similar data sets and statistical analysis techniques, the added dimension of geographic size associated with the locally-enhanced magnetic field in the supplemental GMD event is only generally characterized due to the limited number of events and data available to characterize the phenomenon. For this reason, the TPL-007-2 standard drafting team included general guidance for assessing enhancements in areas occupying "a relatively narrow band of geomagnetic latitude (on the order of 100 km) and wider longitudinal width (on the order of 500 km)" but noted that these values are "reasonable but not

values for the benchmark GMD event. Results of the study using over 40 years of geomagnetic field data from Canadian observatories estimate the 100-year peak geoelectric field at reference location to be slightly less than the 8 V/km specified in the benchmark GMD event. Furthermore, the researchers used individual station geomagnetic field data without averaging over areas (i.e., the research was not based on spatial averaging). *See* L. Nikitina et al., *Assessment of extreme values in geomagnetic and geoelectric field variations for Canada*. 14 SPACE WEATHER 481-494 (2016) (the 100-year geoelectric field value for Ottawa is 2.8 V/km, which is 5 V/km at the reference latitude of 60 degrees geomagnetic latitude). Research being performed as part of the GMD Research Work Plan and by other organizations such as Natural Resources Canada continue to be useful in evaluating the benchmark GMD event used in the TPL-007 standard.

definitive."[27] As the Commission notes, the proposed standard affords flexibility to entities to determine the geographic size of the supplemental GMD event.[28] The type of mitigation that may be required for the supplemental GMD event could vary significantly, however, depending on how and where the planner models the localized enhancement. Further, based on its extensive experience in system planning and the relative immaturity of tools and methods for modeling localized enhancements, the TPL-007-2 standard drafting team determined that many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area.[29] By assuming that the localized extremes would be expansive, and not confined in area and impact, entities would be assessing their vulnerabilities to an event estimated to be highly unlikely, more extreme than a 1-in-200 year event. NERC does not believe that the Commission intended in Order No. 830 for a NERC Reliability Standard to require entities to develop Corrective Action Plans to provide complete mitigation for all potential vulnerabilities identified by applying localized peak values over an entire planning area in this way,[30] nor would such an approach necessarily promote the interests of prudent system planning.

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[27] Petition at 11-13 and Ex. I (Supplemental GMD Event Description White Paper) at 13.

[28] NOPR at P 36.

[29] *See* Petition, Exhibit I (Supplemental GMD Event Description White Paper) at 13.

[30] *See* Order No. 830 at P 36, in which the Commission explained the NOPR proposal underlying its directive as follows (emphasis added):

> Specifically, the NOPR proposed to direct NERC to modify the reference peak geoelectric field amplitude component of the benchmark GMD event definition so that it is not calculated based solely on spatially-averaged data. The NOPR explained that this could be achieved, for example, by requiring applicable entities to conduct GMD Vulnerability Assessments (and, as discussed below, thermal impact assessments) using two different benchmark GMD events: the first benchmark GMD event using the spatially-averaged reference peak geoelectric field value (8 V/km) and the second using the non-spatially averaged peak

NERC does not believe that concerns regarding the uncertainty of the geographic size of the supplemental GMD event could be addressed adequately by sensitivity analysis or through other methods in planning studies.[31] Sensitivity analysis can be useful component of planning studies. However, as many entities are performing GMD studies using complex engineering and geophysical models for the first time, there are inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) that may be subject to sensitivity analysis and would produce differences in GMD Vulnerability Assessment results. NERC believes introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments. Such issues would be better addressed through research.

Further, while some commercially-available modeling tools now advertise capabilities that could be used to model localized GMD enhancements,[32] to NERC's knowledge these capabilities have not been used extensively by planners, nor have the different software tools

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> geoelectric field value cited in the GMD Interim Report (20 V/km). The NOPR stated that the revised Reliability Standard could then require applicable entities to take corrective actions, using engineering judgment, based on the results of both assessments. **The NOPR explained that applicable entities would not always be required to mitigate to the level of risk identified by the non-spatially averaged analysis; instead, the selection of mitigation would reflect the range of risks bounded by the two analyses, and be based on engineering judgment within this range, considering all relevant information.** The NOPR stated that, alternatively, NERC could propose an equally efficient and effective modification that does not rely exclusively on the spatially-averaged reference peak geoelectric field value.

See also NOPR at P 40 ("[W]e agree with NERC that any required mitigation of supplemental GMD event vulnerabilities should be flexible in terms of how applicable entities choose to mitigate such vulnerabilities.").

[31] *See Id*. at P 36 ("NERC contends that the low number of real-world observations on which the supplemental GMD event is based calls into question the accuracy of its geographic size. However, any uncertainty regarding the size of the geographic footprint of the supplemental GMD event could be addressed by applicable entities through sensitivity analysis and other methods within planning studies.").

[32] *See Id*. at P 38 and n.47 (citing two examples of modeling suites that advertise this capability).

been benchmarked for consistency in results. Furthermore, underlying assumptions related to the size and spatial characteristics of the enhancement are the subject of ongoing research. NERC anticipates that these tools and capabilities will continue to evolve and mature, and it will continue to support such efforts through the NERC GMD Task Force. Given the variations in modeling localized peak enhancements, it is appropriate for the TPL-007 standard to continue to require the development of Corrective Action Plans, plans which could call for extensive planning and capital expenditures, only for the benchmark GMD Vulnerability Assessments.

To conclude, NERC maintains that the proposed standard strikes the appropriate balance between the urgency to address GMD-related vulnerabilities and providing flexibility consistent with principles of prudent, cost-effective, risk-based system planning. By requiring the entity to evaluate which actions can be taken to address vulnerabilities to the supplemental GMD event, the standard maintains a high bar for reliability. At the same time, the standard affords the entity sufficient flexibility to determine whether to supplement an existing Corrective Action Plan based on the benchmark GMD event with additional measures based on its engineering judgment and in light of any other relevant considerations. The proposed standard thus addresses the Commission's concerns from Order No. 830 in a clear, rigorous, results-based Reliability Standard.

c) NERC's Review of the TPL-007-2 Standard Provides the Proper Forum for Evaluating the Standard in Light of New Technical and Scientific Understanding

In Order No. 830, the Commission directed NERC to perform activities to improve scientific and technical understanding of GMD events. In response, NERC developed and submitted to the Commission its Order No. 830 GMD Research Work Plan. NERC is currently executing this plan, which includes several Tasks relevant to the issues identified in this NOPR. Specifically, Task 1 – *Further Analyze Spatial Averaging Used in the Benchmark GMD Event*

consists of two main research components: (i) research to improve understanding of the characteristics and spatial scales of localized geoelectric field enhancements caused by severe GMD events; and (ii) research to determine the impacts of spatial averaging assumptions on BPS reliability.[33] One aim of the research is to improve understanding of characteristics and spatial scales of localized geoelectric field enhancements, which could inform the supplemental GMD event.

NERC is concerned that the timing of the Commission's proposed directive (i.e., to submit a revised standard 12 months following the effective date of TPL-007-2) could, depending on the effective date of a final rule in this proceeding, require NERC to initiate development of a revised standard prior to the completion of its important and directly relevant GMD research work. As explained in more detail in NERC's GMD Research Work Plan filing, NERC expects that the last of the project's deliverables will be ready by early 2020. Any scientific research project schedule, however, must account for the possibility that additional time may be needed to explore potential findings or amend project approaches to provide more useful results. NERC also needs to account for additional time, following delivery of the technical reports and other project deliverables, to allow interested entities an opportunity to review and provide comments consistent with the Commission's guidance.[34] These comments could provide additional insights and further areas for consideration. For these reasons, NERC does not anticipate that the GMD Research Work Plan would be fully completed before late 2020, even assuming that the work proceeds generally as scheduled. NERC believes that it is important that this work be completed in full prior to considering further revisions to the TPL-007 standard.

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[33] *See* GMD Research Work Plan, *supra* note 5, at 2-7.

[34] In its Order accepting NERC's preliminary plan, the Commission stated that it "expects NERC to afford interested entities an opportunity to comment on GMD Work Plan deliverables before they are filed with the Commission." *Order on GMD Research Work Plan*, 161 FERC ¶ 61,048, at P 17 (2017).

As noted earlier in these comments, NERC commits to initiate a review of TPL-007-2 following the completion of the GMD Research Work Plan to evaluate whether the standard continues to be supported by the available knowledge or whether additional refinements are necessary. This review could result in modifications to, or additional support for, the proposed supplemental GMD event, and thereby inform what the TPL-007 standard should require in terms of mitigation based on supplemental GMD Vulnerability Assessments. To promote the efficient use of standard development resources and to avoid the burden associated with implementing multiple successive versions of a standard, NERC respectfully requests that the Commission await the completion of NERC's GMD research work and NERC's subsequent review prior to issuing any directives requiring further modifications to the standard.

B. Extending Corrective Action Plan Deadlines

1. NOPR

In the NOPR, the Commission expressed concern that proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.4, which allows entities to extend their Corrective Action Plan deadlines in limited circumstances, "contrasts with the Commission's guidance in Order No. 830 that 'NERC should consider extensions of time on a case-by-case basis.'"[35] The Commission stated that it "agree[s] with NERC that there should be a mechanism for allowing extensions of … deadlines," but that it would like to "avoid unnecessary delay in implementing protection against GMD threats."[36] The Commission, therefore, seeks comments on two proposals to address the situation where an entity cannot complete the implementation of a

[35] NOPR at P 45 (citing Order No. 830 at P 102).

[36] *Id.* at P 46.

Corrective Action Plan to address GMD vulnerabilities within the timetable specified by proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3.[37]

Under the first option, the Commission proposes to direct NERC to modify the standard to require NERC and the Regional Entities to consider any requests for extension of time on a case-by-case basis. Entities seeking an extension of Corrective Action Plan deadlines would be required to submit a request to NERC and the Regional Entities containing the information that would be required by proposed TPL-007-2 Requirement R7 Part 7.4. In addition, the Commission would direct NERC to submit a report addressing the disposition of any such requests and the circumstances under which entities are exceeding Corrective Action Plan deadlines within 12 months from the date on which applicable entities must comply with the last requirement of TPL-007-2, following which the Commission would determine whether further action is necessary.[38]

Under the second option, the Commission would approve proposed TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC. The Commission would also direct NERC to submit a report regarding how often and why entities are exceeding Corrective Action Plan deadlines within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2, following which the Commission would determine whether further action is necessary.[39]

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[37] As directed by the Commission in Order No. 830, proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3 provides that each Corrective Action Plan required by the standard shall include a timetable that specifies completion of non-hardware mitigation within two years of from the development of the Corrective Action Plan and completion of hardware mitigation within four years from the development of the Corrective Action Plan.

[38] NOPR at P 50.

[39] *Id*. at P 51.

2. Comments

NERC supports the Commission's second proposal; that is, to approve Reliability Standard TPL-007-2 Requirement R7 Part 7.4 as proposed by NERC. Proposed Reliability Standard TPL-007-2 Requirement R7 Part 7.3 accomplishes the Commission's overarching goal from Order No. 830 of assuring timely mitigation of GMD vulnerabilities in accordance with the Commission's specified deadlines. Proposed Requirement R7 Part 7.4 accounts for the circumstances under which meeting those deadlines may not be achievable. Placing these requirements into the standard provides clarity and certainty regarding when an entity may extend a Corrective Action Plan mitigation deadline and what steps must be followed to maintain accountability and thus compliance with the standard. This standards-based approach also avoids the administrative burden, uncertainty, and further delay that could be associated with implementing a new ERO adjudication process, such as one that would be dedicated to evaluating GMD Corrective Action Plan deadline extensions on a case-by-case basis.

NERC shares the Commission's concern, as stated in Order No. 830 and reiterated in the NOPR, that entities should not unnecessarily delay efforts to mitigate identified GMD vulnerabilities. NERC submits that proposed Requirement R7 Part 7.4 accounts for this concern. Under the proposed provision, an entity may extend a Corrective Action Plan deadline only where "situations beyond the control of the responsible entity" are the cause for delay. Such situations could include lengthy legal or regulatory processes, stakeholder processes required by tariff, or long equipment lead times, to cite a few examples. The proposed provision was drafted with the goal of providing entities with sufficient flexibility to choose the optimal mitigation strategies for their areas; it is not so flexible, however, as to allow entities to extend Corrective Action Plan deadlines indefinitely or for any reason whatsoever. As part of the compliance monitoring and enforcement activities for the proposed standard, NERC and Regional Entity

staff would exercise their authority to review the reasonableness of any Corrective Action Plan delay, including reviewing the "situations beyond the control of the responsible entity" that are cited as causing the delay.

The proposed provision also contains requirements to maintain accountability when entities extend Corrective Action Plan deadlines. These steps include documenting, in the Corrective Action Plan itself, the circumstances that are causing the delay in implementing the selected mitigation, a description of any changes to the original plan or prior revised plan(s), and revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected options. The entity would be required to update its plan at least every 12 months until implemented. Additionally, under Requirement R7 Part 7.5, an entity would be required to provide the revised plan to its Reliability Coordinator as well as other recipients of the original plan within 90 days of the revision.

Both NERC's proposed standard-based approach and the Commission's proposed "case by case" determination approach would promote timely mitigation of GMD vulnerabilities subject only to reasonable and limited exceptions. The standard-based approach, however, would provide several benefits a case-by-case adjudication model would not. First, if approved, the proposed provision would be monitored through well-established ERO Enterprise Compliance Monitoring and Enforcement Program processes, along with the other Requirements of the proposed TPL-007 standard. If the Commission adopted its first proposal and required NERC to pre-approve individual Corrective Action Plan extensions and plan updates instead, NERC may need to develop and implement a new ERO adjudication process specifically for evaluating

GMD Corrective Action Plan extension requests.[40] Second, the standard-based approach imposes no more administrative burden than is necessary for reliability. In this particular context, a case-by-case adjudication model would likely result in a greater administrative burden to registered entities and NERC and the Regional Entities alike, for no additional reliability benefit. Lastly, the standard-based approach prioritizes timely completion of the actions entities have chosen to mitigate their GMD vulnerabilities. NERC is concerned that the uncertainty associated with a case-by-case adjudication model could result in entities further delaying action to implement their selected GMD mitigation actions while they await the results of a NERC or Regional Entity determination or appeal.

While NERC maintains that proposed Requirement R7 Part 7.4 accomplishes the reliability goal of timely GMD mitigation efficiently and effectively, NERC agrees that a report describing the results of NERC's monitoring of this provision could provide useful information. NERC therefore commits to file the report proposed by the Commission in the NOPR.[41] Specifically, NERC commits to prepare and submit to the Commission a report that describes how often and the reasons why entities in the United States are exceeding Corrective Action Plan deadlines. NERC commits to file this report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2.

[40] One model for such a process could be the Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System, Appendix 5C to the NERC ROP.

[41] *See* NOPR at P 51.

III. Conclusion

For the reasons set forth above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

Date: July 23, 2018

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 23rd day of July, 2018.

/s/ Lauren A. Perotti

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Counsel for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

August 7, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Informational Filing Dated June 29, 2018, Docket No. RM13-11-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits a supplement to the informational filing submitted to the Federal Energy Regulatory Commission ("Commission") in this docket on June 29, 2018[1] ("Informational Filing"). This supplement is submitted to provide additional information that in the Western Interconnection, 18 Balancing Authorities met their compliance obligations during the initial year of implementation of Reliability Standard BAL-003-1.1 through participation in a Frequency Response Sharing Group managed by the Northwest Power Pool. NERC is not requesting any Commission action on the instant filing. NERC respectfully requests that the Commission accept this filing for informational purposes only.

Respectfully submitted,

/s/ Candice Castaneda
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cc: Official service list in Docket No. RM13-11-000

[1] *Informational Filing of the North American Electric Reliability Corporation*, Docket No. RM13-11-000 (June 29, 2018).

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. RM13-11-000.

Dated at Washington, D.C. this 7th day of August, 2018.

/s/ Courtney Baughan
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PER-003-2 AND RETIREMENT OF RELIABILITY STANDARD PER-004-2

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July 23, 2018

TABLE OF CONTENTS

I. BACKGROUND 3
A. Regulatory Framework 3
B. NERC Reliability Standards Development Procedure 4
II. JUSTIFICATION FOR PROPOSED RELIABILITY STANDARD PER-003-2 4
III. JUSTIFICATION FOR THE RETIREMENT OF RELIABILITY STANDARD PER-004-2 5
A. The Requirement for Adequately Trained and NERC-Certified Operators is Redundant with other Reliability Standards 6
B. The Requirements for Reliability Coordinators to Staff Operators 24 Hours a Day, Seven Days Per Week and to Have the Best Available Information around System Operating Limits, Interconnection Reliability Operating Limits, and Inter-Tie Facility Limits are Redundant with other Reliability Standards. 7
IV. EFFECTIVE DATE 9
V. CONCLUSION 9

Exhibit A Proposed Reliability Standard PER-003-2 – Personnel Credentials

Exhibit B Implementation Plan for Proposed Reliability Standard PER-003-2

Exhibit C Order No. 672 Criteria for Proposed Reliability Standard PER-003-2

Exhibit D Summary of Development History and Complete Record of Development

Exhibit E Standard Drafting Team Roster for Project 2017-02

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PER-003-2 AND RETIREMENT OF RELIABILITY STANDARD PER-004-2

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard PER-003-2 (*Operating Personnel Credentials*). NERC requests that the Commission approve the proposed Reliability Standard (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also proposes that the Commission approve the associated implementation plan (**Exhibit B**) and the retirement of the currently-effective Reliability Standards PER-003-1 and PER-004-2, upon Commission approval of the proposed Reliability Standard.

Pursuant to Section 39.5(a) of the Commission's regulations,[4] this Petition presents the technical basis and purpose of proposed Reliability Standard PER-003-2, a summary of the development history (**Exhibit D**), and a demonstration that the proposed Reliability Standard

[1] 16 U.S.C. § 824o (2012).
[2] 18 C.F.R. § 39.5 (2018).
[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).
[4] 18 C.F.R. § 39.5(a).

meets the criteria identified by the Commission in Order No. 672 (**Exhibit C**).[5] The NERC Board of Trustees ("Board") adopted the proposed PER-003-2 Reliability Standard on May 10, 2018.

The purpose of proposed Reliability Standard PER-003-2 is to ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System ("BES"). The proposed Reliability Standard was developed following a periodic review of currently effective Reliability Standard PER-003-1. The proposed revision reflects the recommendation of the Project 2016 EPR-01 PER Periodic Review Team to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

NERC also proposes to implement the recommendation of the Enhanced Periodic Review of Personnel, Performance, Training, and Qualifications Standards Team in Project 2016-EPR-01 ("PER PRT") to retire Reliability Standard PER-004-2. This Reliability Standard falls within Paragraph 81 Criterion B7, because its Requirements are redundant with Requirements in other FERC-approved Reliability Standards that are in effect or that will soon take effect.

For reasons discussed more fully in this Petition, NERC respectfully requests that the Commission approve proposed Reliability Standard PER-003-2 and the retirement of PER-003-1

[5] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

and PER-004-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

I. BACKGROUND

A. Regulatory Framework

In the Energy Policy Act of 2005,[6] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk Power System ("BPS"). Congress also entrusted the Commission with certifying an Electric Reliability Organization ("ERO") charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.[7] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[8] Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States and each modification to a Reliability Standard that the ERO proposes should be made effective.[9]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[10] and Section 39.5(c) of the Commission's regulations, "the

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6 16 U.S.C. § 824o.

7 *Id.* § 824o(b)(1).

8 *Id.* § 824o(d)(5).

9 18 C.F.R. § 39.5(a).

10 16 U.S.C. § 824o(d)(2).

Commission will give due weight to the technical expertise of the Electric Reliability Organization" with respect to the content of a Reliability Standard.[11]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[13]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[14] and thus satisfy certain of the criteria for approving Reliability Standards.[15] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders, and stakeholders must approve, and the NERC Board must adopt, a Reliability Standard before the standard is submitted to the Commission for approval.

II. JUSTIFICATION FOR PROPOSED RELIABILITY STANDARD PER-003-2

As discussed below and in **Exhibit C**, proposed Reliability Standard PER-003-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[11] 18 C.F.R. § 39.5(c)(1).

[12] Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[13] The ROP is *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.

[14] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

[15] Order No. 672 at PP 268, 270.

The requirements in proposed Reliability Standard PER-003-2 remain unchanged from currently effective Reliability Standard PER-003-1. The only proposed modification to the PER-003 standard is to add the following footnote to each requirements: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." The intent of the Standard Drafting Team is to reflect the certifications referenced in the NERC System Operator Certification Program Manual. This proposed footnote provides context for the references to NERC "certificates" in Requirements R1, R2, and R3. No other components of the manual are incorporated into the proposed standard. This clarification aligns with the PER-003 Reliability Standards Audit Worksheet auditor guidance, which provides that the "...Audit Team may contact NERC to confirm the certification information is valid."

III. JUSTIFICATION FOR THE RETIREMENT OF RELIABILITY STANDARD PER-004-2

On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC[16], including the four PER Reliability Standards: PER-001-0, PER-002-0, PER-003-0, and PER-004-1.[17] In Order No. 742, the Commission approved currently-effective Reliability Standard PER-004-2, which includes two requirements.[18] Requirement R1 provides that, [e]ach Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week. Requirement R2 provides that, Reliability Coordinator operating personnel shall place particular attention on [System Operating Limits] and [Interconnection Reliability Operating

[16] Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16415 (2007), FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[17] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1330-1417.
[18] Order No. 742, *System Personnel Training Reliability Standards*, 75 Fed. Reg. 72664 (2010).

Limits] and inter-tie facility limits. . .[and] shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times. NERC proposes to implement the PER PRT recommendation to retire Reliability Standard PER-004-2. This Reliability Standard falls within Paragraph 81 Criterion B7, because its requirements are redundant with requirements in other FERC-approved Reliability Standards that are in effect or that will soon take effect.

A. The Requirement for Adequately Trained and NERC-Certified Operators is Redundant with other Reliability Standards.

PER-004-2 Requirement R1's provision to have "NERC-certified Reliability Coordinator Operators" is addressed in the currently-effective Reliability Standard PER-003-1 (*Operating Personnel Credentials*) Requirement R1, which 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. These System Operators include Reliability Coordinators.

PER-004-2 Requirement R1's provision to have "adequately trained .Reliability Coordinator Operators" is addressed in Reliability Standard PER-005-2 (*Operations Personnel Training*) Requirement R1, which states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of BES company-specific Real-time reliability-related tasks. Additionally, PER-005-2 Requirement R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks. The training mandated by PER-005-2 incorporates reliability-related tasks tailored to the company needs of a given Reliability Coordinator.

B. The Requirements for Reliability Coordinators to Staff Operators 24 Hours a Day, Seven Days Per Week and to Have the Best Available Information around System Operating Limits, Interconnection Reliability Operating Limits, and Inter-Tie Facility Limits are Redundant with other Reliability Standards.

PER-004-2 Requirement R1 calls for staffing 24 hours per day, and seven days per week. Requirement R2 requires Reliability Coordinator operating personnel to examine System Operating Limits ("SOLs"), Interconnection Reliability Operating Limits ("IROLs") and inter-tie facility limit. These staffing and continuous monitoring requirements enable the Reliability Coordinator to maintain a Wide Area view of the BES and to prevent or mitigate emergency operating situations in real-time operations. Pursuant to a suite of requirements under Emergency Preparedness and Operations ("EOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, Reliability Coordinators must be continuously staffed with NERC certified Reliability operators, consistent with PER-004-2, to monitor facilities and analyze SOL and IROL. Failure to be continuously staffed with adequately trained NERC certified operators would result in a Reliability Coordinator's inability to meet their obligations under the EOP and IRO Reliability Standards, as discussed below.

Continuous monitoring is required under Reliability Standard EOP-004-3 (*Event Reporting*) to enable Reliability Coordinators to detect a complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability is rendered inoperable. Any complete loss of monitoring for such period of time is a reportable event pursuant to EOP-004-3.

Reliability Standard IRO-002-5 (*Reliability Coordination – Monitoring and Analysis*) also requires Reliability Coordinators to continuously monitor and analyze data necessary to perform their function. Requirement R5 provides that each Reliability Coordinator must monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the

Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas. This monitoring enables Reliability Coordinators to identify any SOL and IROL exceedances within its Reliability Coordination Area.

Reliability Standard IRO 008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*) similarly identifies the analyses that Reliability Coordinators must perform while monitoring the system to prevent instability, uncontrolled separation or cascading outages. Pursuant to Requirements R1, R2, and R4, the Reliability Coordinator must perform an Operational Planning Analysis to: (a) assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area, (b) ensure that coordinated plans are developed for the next-day operations to address these exceedances, and (c) execute Real-time Assessments at least once every 30 minutes. Finally, Reliability Standard IRO-009-2 (*Reliability Coordinator Actions to Operate within IROLs*) requires Reliability Coordinators to have processes in place to take action, to direct others and to take action, or to mitigate the magnitude and duration of an IROL exceedance. A Reliability Coordinator would not be able to meet these obligations without being continuously staffed with NERC-certified operators on a 24/7 basis, consistent with PER-004-3.

Other Reliability Standards emphasize the need for a Reliability Coordinator to receive quality information, consistent with Requirement R2 of PER-004-2, to perform its function. Reliability Standard IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) requires the Reliability Coordinator to collect data from specified entities to ensure it has the data necessary to perform Operational Planning Analyses, Real-time monitoring and Real-time Assessments. To maintain the validity of this data, the Reliability Coordinator must establish a protocol to resolve data conflicts. Reliability Standard IRO-018-1 (*Reliability Coordinator Real-*

time Reliability Monitoring and Analysis) also emphasizes the need to implement processes and procedures for evaluating the quality of Real-time data and to provide assurance that any action taken addresses data quality issues for Real-time monitoring and Real-time Assessments at all times. Finally, Reliability Standard IRO-014-3 (*Coordination among Reliability Coordinators*) 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.

IV. EFFECTIVE DATE

NERC respectfully requests that the Commission approve proposed Reliability Standard PER-003-2 to become effective as set forth in the proposed implementation plan, provided in Exhibit B hereto. The proposed implementation plan provide that the proposed Reliability Standard shall become effective on the first day of the first calendar quarter that is six calendar months after the effective date of the Commission's order approving the proposed Reliability Standard, or as otherwise provided for by the Commission.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve proposed Reliability Standard PER-003-2 and associated elements, the proposed implementation plan, and the retirement of currently-effective Reliability Standards PER-003-1 and PER-004-2 as discussed herein.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

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Date: July 23, 2018

Exhibit A

Proposed Reliability Standard PER-003-2 – Personnel Credentials

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-2**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2.

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

---

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

---

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

---

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	May 10, 2018	Added footnote to requirements	Revision
2	May 10, 2018	Adopted by Board of Trustees	Revision

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-~~1~~2**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2. ~~In those jurisdictions where regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after Board of Trustees adoption.~~

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [1][2]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

1.1.4. System operations

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

1.1.5. Protection and control

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

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[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	January 22, 2018	Added footnote to requirements	Revision
2	May 10, 2018	Adopted by Board of Trustees	Revision

Exhibit B

Implementation Plan for Proposed Reliability Standard PER-003-2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-02 Operating Personnel Credentials

Requested Approvals

- PER-003-2 Operating Personnel Credentials

Requested Retirements

- PER-003-1 Operating Personnel Credentials
- PER-004-2 Reliability Coordination - Staffing

Applicable Entities

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Effective Date

The effective date for proposed Reliability Standard PER-003-2 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard PER-003-2 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PER-003-2 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standards PER-003-1 and PER-004-2 shall be retired immediately prior to the effective date of the proposed PER-003-2 standard.

Exhibit C

Order No. 672 Criteria for Proposed Reliability Standard PER-003-2

Exhibit C — Order No. 672 Criteria — Proposed Reliability Standard PER-003-2

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The purpose of proposed Reliability Standard PER-003-2, which is unchanged from currently-effective Reliability Standard PER-003-1, is to ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System ("BES"). Specifically, proposed Reliability Standard PER-003-2 requires System Operators who are filling a Real-time operating position for a Reliability Coordinator, Balancing Authority or Transmission Operator to be NERC Certified through the NERC System Operator Certification Program. The proposed standard also requires that System Operators demonstrate minimum competencies necessary for their particular operating position.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321, 324.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard is applicable only to users, owners, and operators of the bulk power system and is clear and unambiguous as to what is required and who is to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Reliability Coordinators, Transmission Operators and Balancing Authorities. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard, each of which are triggered by articulated actions and situations.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Severity Levels ("VSLs") for the proposed Reliability Standard, comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level of each VSL is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear an understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standard includes a Measure that support the proposed standard's sole Requirement by clearly identifying what is required and how the Requirement will be enforced. This Measure, which remains substantively unchanged from the Measure in currently-

[3] Order No. 672 at P 322, 325.

[4] Order No. 672 at P 326.

[5] Order No. 672 at P 327.

effective Reliability Standard PER-003-2, helps provide clarity regarding how the Requirement will be enforced, and helps ensure that the Requirement will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed revisions reflected in proposed Reliability Standard PER-003-2 effectively address the recommendation of the Project 2016 EPR-01 PER Periodic Review Team to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual and (ii) that the certifications referenced under currently-effective Reliability Standard PER-003-1 are those under the NERC System Operator Certification Program.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, proposed PER-003-2 represents a significant improvement over the previous version as described herein.

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[6] Order No. 672 at P 328.

[7] Order No. 672 at PP 329, 330.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

The proposed Reliability Standard has no undue negative effect on competition. The proposed Reliability Standard requires the same performance by each of applicable entity. The proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.[10]**

The proposed effective date for the PER-003-2 is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for the proposed Reliability Standard on the first day of the first calendar quarter that is six months after the effective date of the applicable regulatory approval. The proposed implementation period are designed to allow sufficient time for the applicable entities to make any changes in their internal process necessary to implement the proposed revisions. The proposed effective date is explained in the proposed Implementation Plan, attached as **Exhibit B**.

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8 Order No. 672 at P 331.

9 Order No. 672 at P 332.

10 Order No. 672 at P 333.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards.[12] **Exhibit E** includes a summary of the proposed standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard PER-003-2. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors relevant to whether the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential were identified.

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[11] Order No. 672 at P 334.

[12] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

[13] Order No. 672 at P 335.

[14] Order No. 672 at P 323.

Exhibit D

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard PER-003-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Standard Drafting team ("SDT") members is included in Exhibit E.

II. Standard Development History

A. Standard Authorization Request Development

Project 2017-02 – Modifications to Personnel Performance, Training, and Qualifications Standards was initiated in direct relation to recommendations provided by the Project 2016-EPR-01 – Personnel, Performance, Training, and Qualifications (PER) Standards Periodic Review Team ("PER PRT") to add clarity to the currently-effective PER-003-1 standard that explains that the NERC certifications identified in this standard are described in the NERC System Operator Certification Program. Specifically, the PER PRT developed a recommendation 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 Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).

[2] The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

The Standards Authorization Request ("SAR") for Project 2017-02 was posted for an initial 30-day informal comment period from June 21, 2017 through July 24, 2017. The SAR was accepted by the Standards Committee on June 14, 2017.

B. First Posting - Comment Period, Initial Ballots

Proposed Reliability Standard PER-003-2 and the associated Implementation Plan, were posted for a 45-day formal comment period from January 22, 2018 through March 7, 2018, with parallel Initial Ballots for proposed the standard held during the last 10 days of the comment period from February 26, 2018 through March 7, 2018. The Initial Ballot for proposed Reliability Standard PER-003-2 received 80.93% quorum, and 97.50% approval. The Initial Ballot for the proposed Implementation Plan received 81.27% quorum, and 98.91% approval. There were 30 sets of responses, including comments from approximately 97 different individuals and approximately 76 companies, representing all of the 10 industry segments.[3]

C. Final Ballots

Proposed Reliability Standard PER-003-2 and the associated Implementation Plan were posted for a 10-day final ballot period from April 3, 2018 through April 12, 2018. The final ballot for proposed Reliability Standard PER-003-2 reached quorum at 84.82% of the ballot pool, and the proposed standard received sufficient affirmative votes for approval, receiving support from 96.64% of the voters.[4] The final ballot for proposed Implementation Plan reached quorum at

[3] NERC, *Consideration of Comments*, Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards (PER-003-2 and Implementation Plan), (March 26, 2018), *available at* https://www.nerc.com/pa/Stand/201702_Modifications_to_PER_Standards_DL/2017-02_Mod_PER_Standards_Consideration_of_Comments_04032018.pdf.

[4] NERC, Ballot Results (PER-003-2), *available at* https://sbs.nerc.net/BallotResults/Index/245.

84.86% of the ballot pool, and the proposed Implementation Plan received sufficient affirmative votes for approval, receiving support from 97.88% of the voters.[5]

D. Board of Trustees Adoption

Proposed Reliability Standard PER-003-2 was adopted by the NERC Board of Trustees on May 10, 2018.[6]

[5] NERC, Ballot Results (Implementation Plan), *available at* https://sbs.nerc.net/BallotResults/Index/246.

[6] NERC, *Board of Trustees Agenda Package*, Agenda Item 7a (PER-003-2 — Operating Personnel Credentials), *available at* https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Meeting_Agenda_Package_May_10_2018.pdf.

Complete Record of Development

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications

Status
Final ballots for the following concluded **8 p.m. Eastern, Thursday, April 12, 2018**.

- PER-003-2 Operating Personnel Credentials
- PER-003-1 Operating Personnel Credentials – Retirement
- PER-004-2 Reliability Coordination-Staffing – Retirement

The voting results can be accessed via the links below. The standard and implementation plan will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background
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) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.

Standard(s) Affected – PER-003-1 and PER-004-2

Purpose / Industry Need
A clarifying footnote needs to be added to PER-003-1 Requirement R1, R2 and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

The PER-004-2 standard falls within Paragraph 81 Criterion B7 and should be retired. 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. 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

Draft	Actions	Dates	Results	Consideration of Comments
Final Ballots PER-003-2 Clean **(25)** | Redline to Last Approved **(26)** Implementation Plan **(27)**	Final Ballots Info **(28)** Vote	04/03/18 - 04/12/18	Ballot Results PER-003-2 **(29)** Implementation Plan **(30)**	
Draft 1 PER-003-2 Clean **(14)** | Redline to Last Approved **(15)** Implementation Plan **(16)** **Supporting Materials** Unofficial Comment Form (Word) **(17)**	Initial Ballots Updated Info **(21)** Info **(22)** Vote	02/26/18 - 03/07/18	Ballot Results PER-003-2 **(23)** Implementation Plan **(24)**	Consideration of Comments **(20)**
	Comment Period Info **(18)** Submit Comments	01/22/18 - 03/07/18	Comments Received **(19)**	

	Join Ballot Pools	01/22/18 - 02/20/18		
Standards Authorization Request **(7)** **Supporting Materials** **Periodic Review Templates** PER-003-1 **(8)** PER-004-2 **(9)** Unofficial Comment Form (Word) **(10)**	Comment Period Info **(11)** Submit Comments	06/21/17 - 07/24/17	Comments Received **(12)**	Consideration of Comments **(13)**
Periodic Review Templates PER-003-1 **(1)** PER-004-2 **(2)** **Supporting Materials** Unofficial Comment Form (Word) **(3)**	Comment Period Info **(4)** Submit Comments	01/10/17 - 02/23/17	Comments Received **(5)**	Consideration of Comments **(6)**

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

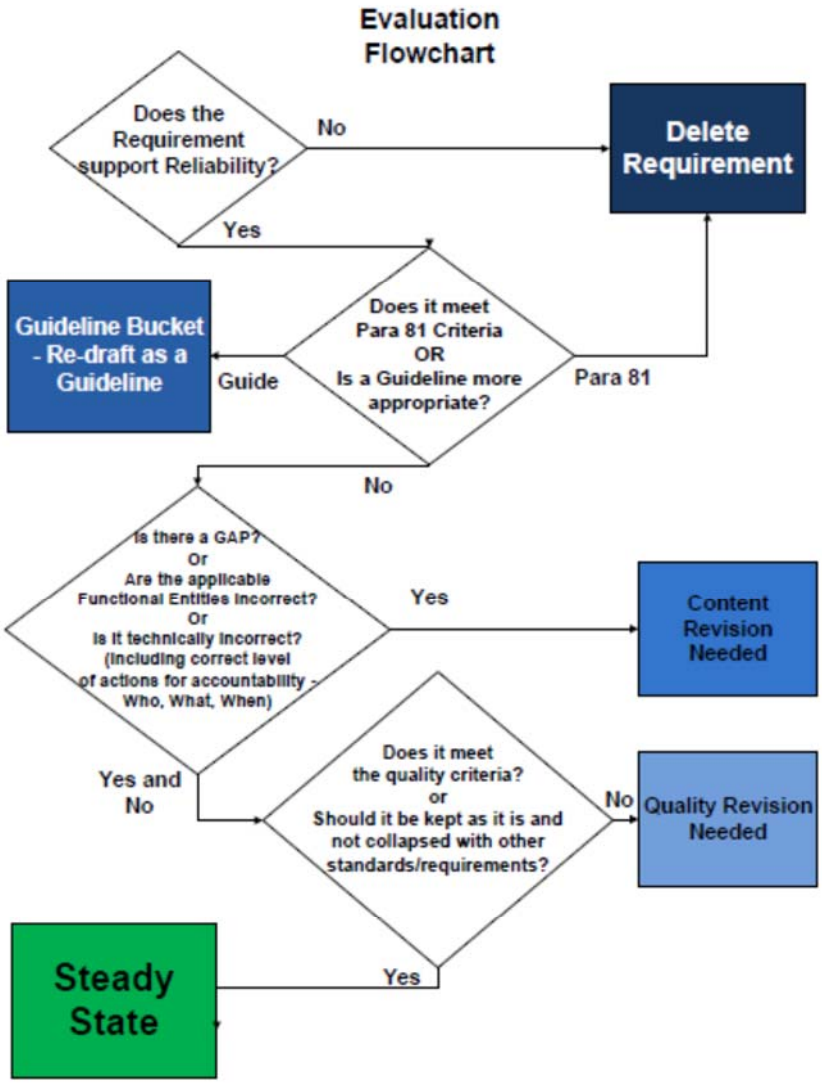

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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

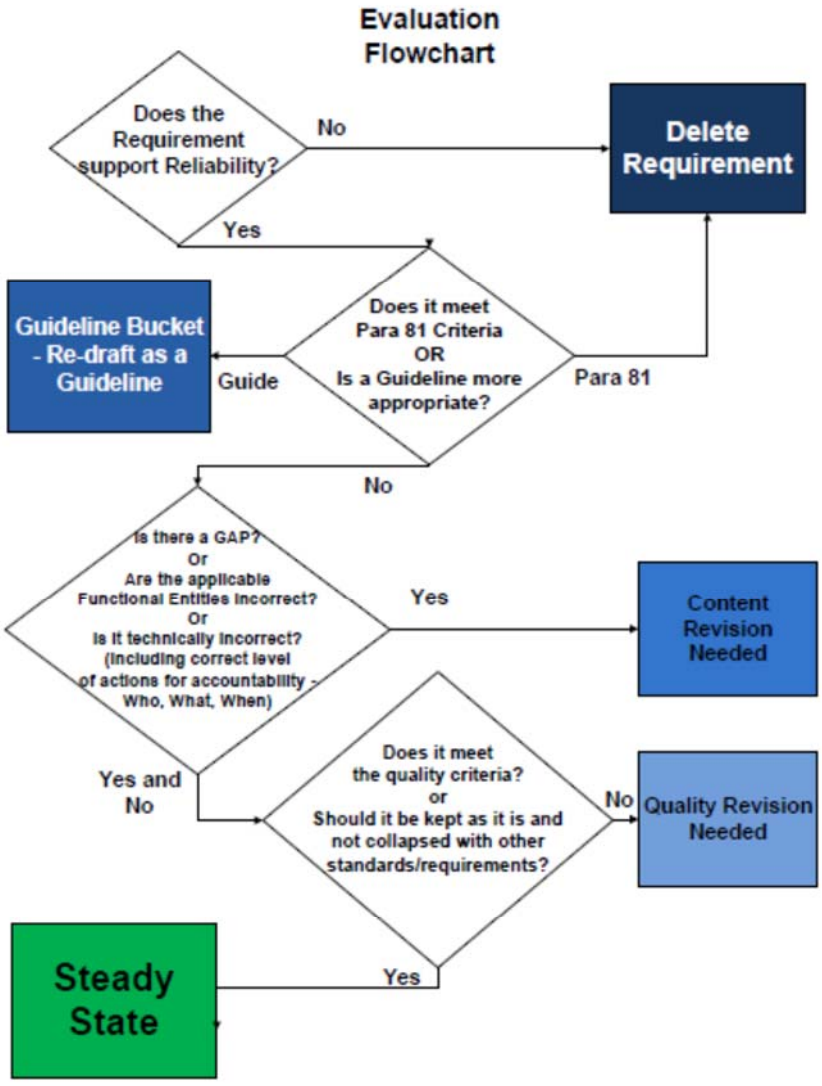

Figure 1: Evaluation Flow Chart

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Unofficial Comment Form

Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards (PER)

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2016-EPR-01 PER** project. The electronic form must be submitted by **8 p.m. Eastern, Thursday, February 23, 2017**.

Documents and information about this project are available on the Project 2016-EPR-01 PER page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background

This periodic review project will review the following three PER standards:

- PER-001-0.2 – Operating Personnel Responsibility and Authority;
- PER-003-1 – Operating Personnel Credentials; and
- PER-004-2 – Reliability Coordination – Staffing.

The PER periodic review team (PER PRT) will use the background information, along with any associated worksheets or reference documents (such as the Independent Expert Review Project report, and Paragraph 81 criteria) to guide a comprehensive review that results in a recommendation from one of the following three choices:

1. Recommend re-affirming the standard;
2. Recommend revising the standard; or
3. Recommend retirement of the standard.

If the PER PRT recommends a revision to, or a retirement of, the standard, it must also submit a Standard Authorization Request to the Standards Committee outlining the proposed scope and technical justification for the revision or retirement.

PER-001-0.2 was initially included in this project. However, the standard was subsequently approved for retirement under FERC Order 817. Therefore this project will only review PER-003-1 and PER-004-2.

Questions

1. The PER PRT 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. Do you agree with the recommendation? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

2. The PER PRT recommends that PER-004-2 be retired. The PER PRT believes that the requirements in PER-004-2 are duplicative with several other standards as outlined in the PER-004-2 EPR template. Do you agree with the recommendation? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

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Standards Announcement

Project 2016-EPR-01 Enhanced Periodic Review of Personnel, Performance, Training, and Qualifications (PER) Standards

Formal Comment Period Open through February 23, 2017

Now Available

A 45-day formal comment period for the **Project 2016-EPR-01 Enhanced Periodic Review of PER Standard Templates**, is open through **8 p.m. Eastern, Thursday, February 23, 2017**.

Commenting

Use the electronic form to submit comments on the templates. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2016-EPR-01 Enhanced Periodic Review of PER Standards | Templates for PER-003-1 and PER-004-2
Comment Period Start Date:	1/10/2017
Comment Period End Date:	2/23/2017
Associated Ballots:	

There were 28 sets of responses, including comments from approximately 86 different people from approximately 63 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The PER PRT 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. Do you agree with the recommendation? If not, please explain in the comment area below.

2. The PER PRT recommends that PER-004-2 be retired. The PER PRT believes that the requirements in PER-004-2 are duplicative with several other standards as outlined in the PER-004-2 EPR template. Do you agree with the recommendation? If not, please explain in the comment area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Mark Peter	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC

					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Liz Axson	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and Eversource	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC

					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Diana Scott	Santee Cooper	1	SERC

					Heuguette Bostic	Santee Cooper	1	SERC

1. The PER PRT 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. Do you agree with the recommendation? If not, please explain in the comment area below.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	

Comment

This recommendation may be suitable if the standard was being revised for a substantive reason, but to make a change to the standard to implement this recommendation is unwarranted. The footnote is unnecessary for any RC, TOP, and/or BA stakeholder worthy of performing functions to which this standard applies.

The purpose statement in PER-003-1 specifically states the standard is "To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System."

In addition, requirement 1 specifically references a "...valid NERC Reliability Operator certificate...", while requirements 2 and 3 specifically references "...obtaining and maintaining one of the following valid NERC certificates..." and specifically lists applicable NERC certifications for each requirement.

Further, the PER-003 RSAW has auditor guidance that the "...Audit Team may contact NERC to confirm the certification information is valid." This guidance points to the NERC Syystem Operator Certification Program and associated manual. It would require a tortured argument to point these references to certifications or a certification program other than NERC.

Considering the above references, coupled with historic precedent from previous audits, there should be no need to include a footnote to ensure BAs, TOPs, and RCs "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."

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

AEP believes the standard is sufficiently clear in this regard as currently written. The current version of these requirements all specify NERC certificates, so a direct correlation to the NERC System Operator Certification Program Manual should already be clear. While AEP does not entirely

object to the concept of explicitly referencing the SOC Program Manual in PER-003-1, care should taken to ensure that additional obligations aren't unintentionally implied (say, from the content of the manual itself) by doing so.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Eversource

Answer	No
Document Name	

Comment

While we do not feel strongly one way or the other with the proposed addition of a clarifying footnote, we are unclear on where that footnote will be added, i.e., is it under R1, R2 or R3 or all of the above. We wonder if a seemingly minor change would provide sufficient reliability improvement to warrant the effort needed to effect the change (e.g., forming a drafting team, going through the approval process, etc.). Also, the PER-003-1 EPR template indicates sub-parts (a) to (g), which are not found in the PER-003 standard. This needs to be clarified in the SAR.

There is already a footnote related to each requirement R1, R2 and R3 in PER-003-1 which ties to the NERC Operator Certification Program.

FN1 of PER-003-1 *Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability related tasks.*

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee

Answer	No
Document Name	

Comment

For PER-003-1, it is unclear as to where this footnote will be added, i.e., is it under R1, R2 or R3, or all of the above. This needs to be clarified but the SRC questions whether it is worth the effort in creating a SAR given that there is significant effort involved in creating a SAR, forming a drafting team and processing the proposed changes through the NERC and FERC regulatory processes. SRC is of the opinion that the proposed footnote addition does not provide enough of a justification for the amount of effort needed for the industry to put out a SAR, form a drafting team, recommend changes and get the proposed changes through the NERC and regulatory process.

Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA has no objections to this proposed edit for clarification.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Entergy Agrees with adding a footnote to PER-003-1 Standard.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
We don't think this has been an issue in the past, however we do not object to the clarifying footnote being added.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
The suggested clarification to highlight that certifications required under PER-003-1 must be NERC certifications appears reasonable, particularly in light of the proposed retirement of PER-004-2.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group agrees with the Periodic Review Team's (PRT) recommendation for adding a footnote to provide more clarity in the Standard. Additionally, we suggest the drafting team add a Guideline and Technical Basis (GTB) Section to the Standard to help provide clarity in reference to the Requirements. Also, we suggest reformatting the Measurements in the current Standard. We feel this will help provide consistency with the current formatting of newly developed and revised Standards in reference to the Requirement and Measurement Process. The best example of the current formatting process would be demonstrated in the IRO-002-4 Standard.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	NERC 2012 Exam Study Guide.pdf
Comment	
(1) We agree that a footnote should be added to NERC Reliability Standard PER-003-1 that clarifies its dependency on the NERC System Operator Certification Program. However, we feel the Periodic Review Team (PRT) has neglected to address an urgent compliance gap present following recent changes to the NERC System Operator Certification Program, and urge the PRT to revise its recommendation to identify that a revision to the standard is necessary.	

(2) We observe no complementary mechanism that ties the NERC System Operator Certification Program back to this reliability standard. At a minimum, we expect direct, one-for-one alignment between the areas of competencies and the content domains identified as the framework used to ensure the content validity of each NERC certification exam. From what we observe, these content domains were updated recently in the 2017 NERC Exam Resource Materials posted on the NERC web site (http://www.nerc.com/pa/Train/SysOpCert/Pages/default.aspx). For comparison, we attached a similar list of content domains from 2012. Without this alignment and when the requirements within this standard are taken verbatim, then industry is burdened to demonstrate that a minimum competency has been obtained for applicable staff performing Real-time, company-specific, reliability-related tasks.

(3) The current approach to the interdependencies between this reliability standard and the NERC Continuing Education Program relies on the assumption that all registered entities are also NERC Continuing Education Providers. We find this is not always the case. We believe the minimum set of competencies System Operators must maintain are already addressed by the systematic training approach required by their employers in NERC Reliability Standard PER-005-2. At a minimum, we ask the PRT to document in its recommendations that further coordination with the NERC Personnel Certification Governance Committee is necessary to update the list of Recognized Operator Training Topics, as identified in Appendix A of the NERC System Operator Certification Program Manual. We feel this list needs to be revised with current industry concerns, situation awareness and human performance-centric themes, and available technologies.

(4) We ask the PRT to expand its recommendation to include a footnote reference to the NERC Personnel Certification Governance Committee (PCGC) and the importance of its role in monitoring the performance of the NERC System Operator Certification Program.

Likes 0	
Dislikes 0	

Response

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	

Response

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The PER PRT recommends that PER-004-2 be retired. The PER PRT believes that the requirements in PER-004-2 are duplicative with several other standards as outlined in the PER-004-2 EPR template. Do you agree with the recommendation? If not, please explain in the comment area below.

Scott Downey - Peak Reliability - 1

Answer	No
Document Name	

Comment

Peak respectfully disagrees with the recommendation that PER-004-2 be retired. PER-004-2 R1 states that each Reliability Coordinator shall be staffed 24 hours per day, seven days per week. This requirement is not adequately captured in other standards outlined in the PER-004-2 EPR template. Peak suggests consideration be given to incorporating the 24x7 staffing language into PER-003-1 R1.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

We truly appreciate the efforts of the Periodic Review Team (PRT) on identifying the Paragraph 81 Criteria associated with this particular Standard. The SPP Standards Review Group is in agreeance with the recommendation of retirement of this Standard.

Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Both PER-004-2 requirements do appear to be substantially addressed by other reliability requirements.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
We agree that the requirements of PER-004-2 are duplicative and that it can be retired	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Entergy agrees on the retirement of the PER-004 Standard.	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
However, this organization is not a Reliability Coordinator so PER-004 does not apply to us.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that this Standard is for Reliability Coordinators and does not apply to BPA, therefore BPA has no objections to this proposed recommendation.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Eversource	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2016-EPR-01 Enhanced Periodic Review of PER Standards Templates for PER-003-1 and PER-004-2

Comment Period Start Date: 1/10/2017

Comment Period End Date: 2/23/2017

There were 28 sets of responses, including comments from approximately 86 different people from approximately 63 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. The PER PRT 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. Do you agree with the recommendation? If not, please explain in the comment area below.

2. The PER PRT recommends that PER-004-2 be retired. The PER PRT believes that the requirements in PER-004-2 are duplicative with several other standards as outlined in the PER-004-2 EPR template. Do you agree with the recommendation? If not, please explain in the comment area below.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Mark Peter	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Liz Axson	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7, 8,9,10	NPCC	RSC no Dominion and Eversource	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	UI	3	NPCC
Michele Tondalo	UI	1	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Si Truc Phan	Hydro Quebec	2	NPCC
Helen Lainis	IESO	2	NPCC
Laura Mcleod	NB Power	1	NPCC
MIchael Forte	Con Edison	1	NPCC
Kelly Silver	Con Edison	3	NPCC
Peter Yost	Con Edison	4	NPCC
Brian O'Boyle	Con Edison	5	NPCC
Greg Campoli	NY-ISO	2	NPCC
Kathleen Goodman	ISO-NE	2	NPCC

					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Diana Scott	Santee Cooper	1	SERC
					Heuguette Bostic	Santee Cooper	1	SERC

1. The PER PRT 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. Do you agree with the recommendation? If not, please explain in the comment area below.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	

This recommendation may be suitable if the standard was being revised for a substantive reason, but to make a change to the standard to implement this recommendation is unwarranted. The footnote is unnecessary for any RC, TOP, and/or BA stakeholder worthy of performing functions to which this standard applies.

The purpose statement in PER-003-1 specifically states the standard is "To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System."

In addition, requirement 1 specifically references a "...valid NERC Reliability Operator certificate...", while requirements 2 and 3 specifically references "...obtaining and maintaining one of the following valid NERC certificates..." and specifically lists applicable NERC certifications for each requirement.

Further, the PER-003 RSAW has auditor guidance that the "...Audit Team may contact NERC to confirm the certification information is valid." This guidance points to the NERC Syystem Operator Certification Program and associated manual. It would require a tortured argument to point these references to certifications or a certification program other than NERC.

Considering the above references, coupled with historic precedent from previous audits, there should be no need to include a footnote to ensure BAs, TOPs, and RCs "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."	
Likes 0	
Dislikes 0	
Response	
The PRT was provided information that further clarity was needed for the industry to understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. Therefore the PRT determined that adding the footnote provided the needed clarity. In addition, based on the comments received from this posting, the majority of the industry agrees with the PRT's recommendation.	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP believes the standard is sufficiently clear in this regard as currently written. The current version of these requirements all specify NERC certificates, so a direct correlation to the NERC System Operator Certification Program Manual should already be clear. While AEP does not entirely object to the concept of explicitly referencing the SOC Program Manual in PER-003-1, care should taken to ensure that additional obligations aren't unintentionally implied (say, from the content of the manual itself) by doing so.	
Likes 0	
Dislikes 0	
Response	
The PRT was provided information that further clarity was needed for the industry to understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator	

Certification Program. Therefore the PRT determined that adding the footnote provided the needed clarity. In addition, based on the comments received from this posting, the majority of the industry agrees with the PRT's recommendation.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Eversource	
Answer	No
Document Name	
Comment	
While we do not feel strongly one way or the other with the proposed addition of a clarifying footnote, we are unclear on where that footnote will be added, i.e., is it under R1, R2 or R3 or all of the above. We wonder if a seemingly minor change would provide sufficient reliability improvement to warrant the effort needed to effect the change (e.g., forming a drafting team, going through the approval process, etc.). Also, the PER-003-1 EPR template indicates sub-parts (a) to (g), which are not found in the PER-003 standard. This needs to be clarified in the SAR. There is already a footnote related to each requirement R1, R2 and R3 in PER-003-1 which ties to the NERC Operator Certification Program. FN1 of PER-003-1 *Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability related tasks.*	
Likes 0	
Dislikes 0	
Response	
The PRT was provided information that further clarity was needed for the industry to understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. Therefore the PRT determined that adding the footnote provided the needed clarity. In addition, based on the comments received from this posting, the majority of the industry agrees with the PRT's recommendation.	

The PRT intends to add the footnote to all of the requirements in PER-003-1. The System Operator Certification Program Manual does not address non-certified personnel that are in training to assume System Operator positions. The current footnote addresses those non-certified personnel in training.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
For PER-003-1, it is unclear as to where this footnote will be added, i.e., is it under R1, R2 or R3, or all of the above. This needs to be clarified but the SRC questions whether it is worth the effort in creating a SAR given that there is significant effort involved in creating a SAR, forming a drafting team and processing the proposed changes through the NERC and FERC regulatory processes. SRC is of the opinion that the proposed footnote addition does not provide enough of a justification for the amount of effort needed for the industry to put out a SAR, form a drafting team, recommend changes and get the proposed changes through the NERC and regulatory process.	
Likes 0	
Dislikes 0	
Response	
The PRT was provided information that further clarity was needed for the industry to understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. Therefore the PRT determined that adding the footnote provided the needed clarity. In addition, based on the comments received from this posting, the majority of the industry agrees with the PRT's recommendation. The PRT intends to add the footnote to all of the requirements in PER-003-1.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
BPA has no objections to this proposed edit for clarification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Entergy Agrees with adding a footnote to PER-003-1 Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
We don't think this has been an issue in the past, however we do not object to the clarifying footnote being added.	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The PRT was provided information that further clarity was needed for the industry to understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. Therefore the PRT determined that adding the footnote provided the needed clarity.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
The suggested clarification to highlight that certifications required under PER-003-1 must be NERC certifications appears reasonable, particularly in light of the proposed retirement of PER-004-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group agrees with the Periodic Review Team's (PRT) recommendation for adding a footnote to provide more clarity in the Standard. Additionally, we suggest the drafting team add a Guideline and Technical Basis (GTB) Section to the Standard to help provide clarity in reference to the Requirements. Also, we suggest reformatting the Measurements in the current Standard. We feel this will help provide consistency with the current formatting of newly developed and revised Standards in reference to the Requirement and Measurement Process. The best example of the current formatting process would be demonstrated in the IRO-002-4 Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The EPR PRT is focusing on fixing the substance of the standard. The SDT that is assigned to perform the actual revision to the standard will work with NERC staff to determine the appropriate template.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	NERC 2012 Exam Study Guide.pdf
Comment	
(1) We agree that a footnote should be added to NERC Reliability Standard PER-003-1 that clarifies its dependency on the NERC System Operator Certification Program. However, we feel the Periodic Review Team (PRT) has neglected to address an urgent compliance gap present following recent changes to the NERC System Operator Certification Program, and urge the PRT to revise its recommendation to identify that a revision to the standard is necessary. (2) We observe no complementary mechanism that ties the NERC System Operator Certification Program back to this reliability standard. At a minimum, we expect direct, one-for-one alignment between the areas of competencies and the content domains identified as the framework used to ensure the content validity of each NERC certification exam. From what we observe, these content domains were updated recently in the 2017 NERC Exam Resource Materials posted on the NERC web site	

(http://www.nerc.com/pa/Train/SysOpCert/Pages/default.aspx). For comparison, we attached a similar list of content domains from 2012. Without this alignment and when the requirements within this standard are taken verbatim, then industry is burdened to demonstrate that a minimum competency has been obtained for applicable staff performing Real-time, company-specific, reliability-related tasks.

(3) The current approach to the interdependencies between this reliability standard and the NERC Continuing Education Program relies on the assumption that all registered entities are also NERC Continuing Education Providers. We find this is not always the case. We believe the minimum set of competencies System Operators must maintain are already addressed by the systematic training approach required by their employers in NERC Reliability Standard PER-005-2. At a minimum, we ask the PRT to document in its recommendations that further coordination with the NERC Personnel Certification Governance Committee is necessary to update the list of Recognized Operator Training Topics, as identified in Appendix A of the NERC System Operator Certification Program Manual. We feel this list needs to be revised with current industry concerns, situation awareness and human performance-centric themes, and available technologies.

(4) We ask the PRT to expand its recommendation to include a footnote reference to the NERC Personnel Certification Governance Committee (PCGC) and the importance of its role in monitoring the performance of the NERC System Operator Certification Program.

Likes 0	
Dislikes 0	

Response

Thank you for your affirmative response and clarifying comment.

(1) The PRT is not aware of any compliance gaps and therefore cannot respond to your concern.

(2) The PRT does not believe that there is a need to modify this standard due to changes in the NERC exam content outline. The competencies identified in the standard are believed to be the minimum competency areas necessary to perform the duties of a System Operator.

(3) The PRT does not agree with your assumption that all registered entities are NERC Continuing Education Providers nor is it required for all entities to be providers. The PCGC reviews the System Operator Certification Manual and Appendix A on an annual basis. The PCGC is completing an update to this manual that should address your concern. (4) The NERC Rules of Procedure address the PCGC role in the NERC System Operator Program.	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	
Response	
Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your affirmative response.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	

2. The PER PRT recommends that PER-004-2 be retired. The PER PRT believes that the requirements in PER-004-2 are duplicative with several other standards as outlined in the PER-004-2 EPR template. Do you agree with the recommendation? If not, please explain in the comment area below.	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Peak respectfully disagrees with the recommendation that PER-004-2 be retired. PER-004-2 R1 states that each Reliability Coordinator shall be staffed 24 hours per day, seven days per week. This requirement is not adequately captured in other standards outlined in the PER-004-2 EPR template. Peak suggests consideration be given to incorporating the 24x7 staffing language into PER-003-1 R1.	
Likes 0	
Dislikes 0	
Response	
The PRT does not agree with your recommendation to incorporate the 24x7 staffing language into PER-003. Entities would not be able to maintain the reliability of the BES in real-time unless those entities are staffed 24x7. In addition, based on the comments received from this posting, the majority of the industry agrees with the PRT's recommendation.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We truly appreciate the efforts of the Periodic Review Team (PRT) on identifying the Paragraph 81 Criteria associated with this particular Standard. The SPP Standards Review Group is in agreeance with the recommendation of retirement of this Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Both PER-004-2 requirements do appear to be substantially addressed by other reliability requirements.	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
We agree that the requirements of PER-004-2 are duplicative and that it can be retired	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Entergy agrees on the retirement of the PER-004 Standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response and clarifying comment.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
However, this organization is not a Reliability Coordinator so PER-004 does not apply to us.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that this Standard is for Reliability Coordinators and does not apply to BPA, therefore BPA has no objections to this proposed recommendation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your affirmative response.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	
Response	
Thank you for your affirmative response.	

End of Report

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PER-003-1 Operating Personnel Credentials and PER-004-2 Reliability Coordination — Staffing		
Date Submitted:	TBD		
SAR Requester Information			
Name:	Patti Metro		
Organization:	Chair - Project 2016-EPR-01 PER		
Telephone:	(703) 907-5817	Email:	patti.metro@nreca.coop
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Need to add clarity to PER-003-1 that explains that the NERC certifications identified in this standard are described in the NERC System Operator Certification Program. The requirements of PER-004-2 are duplicative with requirements in several other standards that explain in detail the staffing requirements of personnel conducting the Reliability Coordinator function.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
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) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
N/A
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Project 2016-EPR-01 PER team recommends that a clarifying footnote be added to PER-003-1 Requirement R1, R2 and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The PER-004-2 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. 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

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2 and R3 to ensure that stakeholders (now and in the future) understand the connection between the Standard and the Program Manual. The PRT suggests for consideration the following language be used for the footnote "The certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program." Concerning PER-004-2, the standards 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

SAR Information
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

SAR Information
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.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☐	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
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

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): January 10, 2017

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)*:

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.

Date submitted to Standards Committee: June 14, 2017

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.

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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

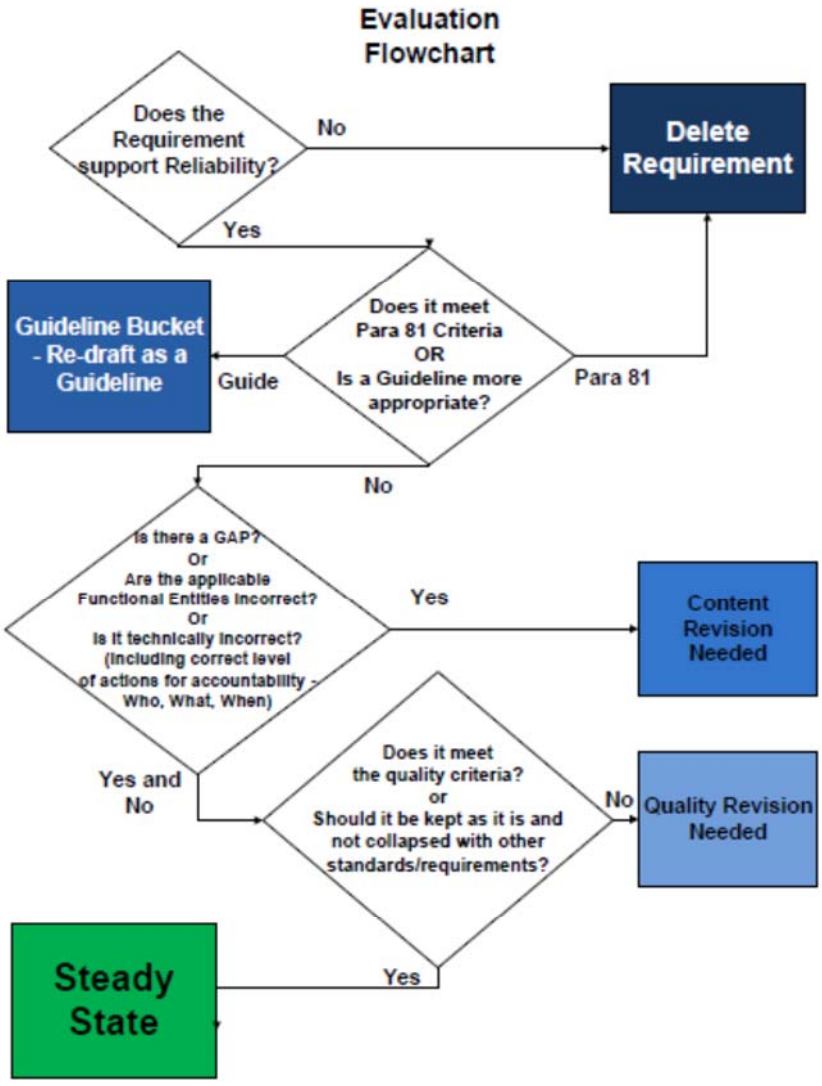

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-004-2 Reliability Coordination - Staffing

December 2016

Introduction

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[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): January 10, 2017

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)*:

See justification above.

Date submitted to Standards Committee: June 14, 2017

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

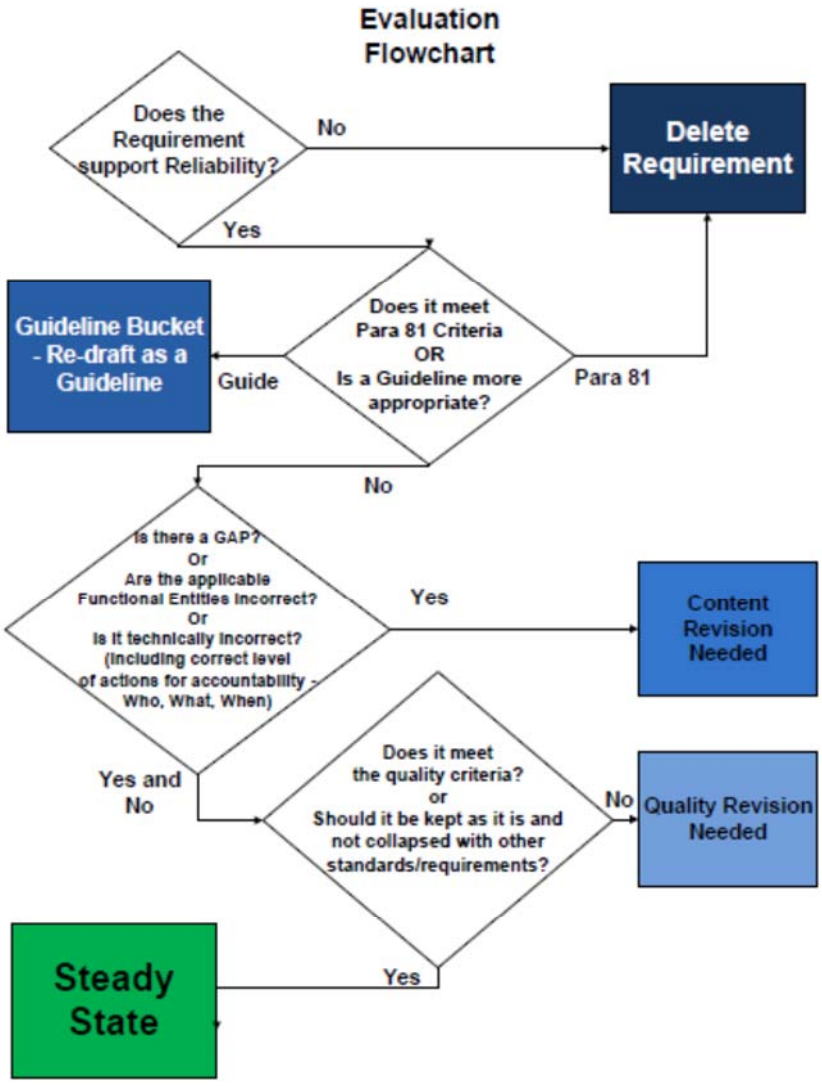

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2017-02 Modifications to Personnel Performance, Training and Qualifications Standards

Do not use this form for submitting comments. Use the electronic form to submit comments on the Standards Authorization Request for the **2017-02 Modifications to Personnel Performance, Training, and Qualifications (PER) Standards** project. The electronic form must be submitted by **8 p.m. Eastern, Monday, July 24, 2016**.

Documents and information about this project are available on the Project 2017-02 Modifications to PER Standards page. If you have questions, contact Senior Standards Developer, Darrel Richardson or at (609) 613-1848.

Background

The periodic review project reviewed the following two PER standards.

- PER-003-1 – Operating Personnel Credentials
- PER-004-2 – Reliability Coordination - Staffing

PER-001-0.2 was not reviewed during the periodic review. This standard was approved for retirement under FERC Order 817. Therefore this project only reviewed PER-003-1 and PER-004-2.

The PER periodic review team (PER PRT) used the background information, along with any associated worksheets or reference documents (such as the Independent Expert Review Project report, and Paragraph 81 criteria) to guide a comprehensive review that would result in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the Standard;
2. Recommend revising the Standard; or
3. Recommend retirement of the standard.

The PER PRT developed this Standard Authorization Request (SAR) to implement their recommendations. The SAR proposes to make a minor modification to PER-003-1 and retire PER-004-2. Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The PRT is recommending that a clarifying footnote be added to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The certifications referenced under the standard are those under the NERC System Operator Certification Program." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

2. The PRT suggests that PER-004-2 be retired based on the identified duplicate requirements. Do you agree that his standard should be retired? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

3. Do you know of any additional requirements that the PRT has not identified to justify the retirement of PER-004-2? If yes, please identify the standard and requirement in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

Informal Comment Period Open through July 24, 2017

Now Available

A 30-day informal comment period on the Standards Authorization Request for the **2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards** project is open through **8 p.m. Eastern, Monday, July 24, 2017**.

Commenting

Use the electronic form to submit comments. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2017-02 Modifications to Personnel Performance, Training, and Qualification Standards
Comment Period Start Date:	6/21/2017
Comment Period End Date:	7/24/2017
Associated Ballots:	

There were 29 sets of responses, including comments from approximately 115 different people from approximately 85 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The PRT is recommending that a clarifying footnote be added to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The certifications referenced under the standard are those under the NERC System Operator Certification Program." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

2. The PRT suggests that PER-004-2 be retired based on the identified duplicate requirements. Do you agree that his standard should be retired? If not, please explain in the comment area below.

3. Do you know of any additional requirements that the PRT has not identified to justify the retirement of PER-004-2? If yes, please identify the standard and requirement in the comment area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	Cooperative Energy	4,6	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					John Shaver	"Arizona Electric Power Cooperative, Inc. "	1	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Midwest Reliability Organization	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC

DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Al DiCaprio	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC

Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Si Truc Phan	Hydro Quebec	2	NPCC
Helen Lainis	IESO	2	NPCC
Laura Mcleod	NB Power	1	NPCC
Michael Forte	Con Edison	1	NPCC
Kelly Silver	Con Edison	3	NPCC
Peter Yost	Con Edison	4	NPCC
Brian O'Boyle	Con Edison	5	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Greg Campoli	NYISO	2	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Sean Bodkin	Dominion - Dominion	6	NPCC

						Resources, Inc.		
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					James Nail	City of Independence Power and Light	3	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Robert Gray	Board of Public Utilities (Kansas City,KS-BPU)	NA - Not Applicable	SPP RE
					Brian Wood	Southwest Power Pool Inc.	2	SPP RE

1. The PRT is recommending that a clarifying footnote be added to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The certifications referenced under the standard are those under the NERC System Operator Certification Program." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

As stated in our previous comments related to Project 2016-EPR-01, AEP believes the standard as currently written is sufficiently clear in this regard. The current version of the standard states that its purpose is "to ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." This, coupled with the references to "NERC Reliability Operator certificate" within the requirements themselves, provides a clear and direct correlation to the certification specified within the NERC System Operator Certification Program Manual. As a result, we see no lack of clarity within the standard. While AEP does not entirely object to the concept of explicitly referencing the SOC Program Manual in the requirements of PER-003-1, extreme care should taken to ensure that additional obligations aren't unintentionally implied by generally referring to the entire manual as a whole.

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy does not believe any clarification is needed. The Purpose states, "To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." No revisions are warranted.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Document Name	

Comment

1. The language listed within this question does not currently align with what is listed within the SAR. We want to confirm that the language proposed does not identify a specific standard revision (i.e. PER-003-1). Furthermore, we propose the footnote references the NERC Personnel Certification Program, as identified within the NERC Rules of Procedure. We propose using this language instead for the footnote, "The NERC certificates referenced in this standard pertain to those identified under the NERC Personnel Certification Program (i.e. NERC System Operator Certification Program)."
2. We feel the SDT has misunderstood our previous comments regarding the Enhanced Periodic Review of the PER Reliability Standards. The scope of PER-003 is to require registered entities to staff Real-time operating positions with NERC-certified System Operators performing reliability-related tasks. Personnel are certified through an examination process that is dictated by the NERC System Operator Certification Program and governed by the NERC Personnel Certification Governance Committee (PCGC). However, with recent changes to the exam, as identified on the NERC web site (http://www.nerc.com/pa/Train/SysOpCert/Pages/default.aspx), we no longer see a one-to-one set of minimum competencies necessary for eligible candidates to possess in order to take the NERC System Operator Certification exam. This places a compliance burden on applicable entities to demonstrate a reasonable assurance that their NERC-certified System Operators have obtained the necessary competencies, as identified within the PER-003-1 standard. We feel this "chicken-and-egg" problem could be entirely avoided by removing the minimum set of competencies from the standard and only requiring applicable entities to staff Real-time operating positions with NERC-certified System Operators performing reliability-related tasks. This would also provide the NERC PCGC more control over the NERC System Operator Certification Program and not conflict with examination and continuing education requirements posted on the NERC web site.
3. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

No comment.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	

Comment

The footnote provides necessary clarity.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We agree that the proposed footnote will provide the necessary clarification, but suggest to change “certifications” to certificates” to conform with the language used in the requirements.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No comment	

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The PRT suggests that PER-004-2 be retired based on the identified duplicate requirements. Do you agree that his standard should be retired? If not, please explain in the comment area below.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned there could be a potential reliability gap in retiring PER-004-2 R1. The SAR argues PER-004-2 is duplicative and all requirements are covered in other reliability standards. Texas RE is concerned that without an explicit requirement to be staffed with NERC-certified operators 24/7 the RCs' control centers may not be staffed with adequately trained personnel. Is the SDT's position that without the explicit obligation in PER-004-2 R1 that there would be a continuing explicit obligation for RCs to be staffed with NERC-certified operators 24/7? If so, please explain and indicate the specific standard requirements including such compliance responsibility.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

We would like to thank the drafting team for their efforts of pointing out the redundancy associated with this standard.

Likes 0	
Dislikes 0	

Response

Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF agrees with the PRT recommendation for retirement of PER-004-2.

Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	
This Standard is not applicable to Manitoba Hydro.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
We are not an RC.	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
PER-004-2 does not apply to BPA as BPA is not registered as a Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	

3. Do you know of any additional requirements that the PRT has not identified to justify the retirement of PER-004-2? If yes, please identify the standard and requirement in the comment area below.

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee

Answer	No
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
PER-004-2 does not apply to BPA as BPA is not registered as a Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	

Document Name	
Comment	
We are not an RC.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	
This Standard is not applicable to Manitoba Hydro.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2017-02 Modifications to Personnel Performance, Training, and Qualification Standards

Comment Period Start Date: 6/21/2017

Comment Period End Date: 7/24/2017

There were 29 sets of responses, including comments from approximately 115 different people from approximately 85 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. **The PRT is recommending that a clarifying footnote be added to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The certifications referenced under the standard are those under the NERC System Operator Certification Program." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.**

2. **The PRT suggests that PER-004-2 be retired based on the identified duplicate requirements. Do you agree that his standard should be retired? If not, please explain in the comment area below.**

3. **Do you know of any additional requirements that the PRT has not identified to justify the retirement of PER-004-2? If yes, please identify the standard and requirement in the comment area below.**

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	Cooperative Energy	4,6	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1,3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					John Shaver	"Arizona Electric Power Cooperative, Inc. "	1	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Midwest Reliability Organization	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
				Seattle City Light Ballot Body	Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Al DiCaprio	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					James Nail	City of Independence Power and Light	3	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Robert Gray	Board of Public Utilities (Kansas City,KS-BPU)	NA - Not Applicable	SPP RE
					Brian Wood	Southwest Power Pool Inc.	2	SPP RE

1. The PRT is recommending that a clarifying footnote be added to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The certifications referenced under the standard are those under the NERC System Operator Certification Program." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	

Comment

As stated in our previous comments related to Project 2016-EPR-01, AEP believes the standard as currently written is sufficiently clear in this regard. The current version of the standard states that its purpose is "to ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." This, coupled with the references to "NERC Reliability Operator certificate" within the requirements themselves, provides a clear and direct correlation to the certification specified within the NERC System Operator Certification Program Manual. As a result, we see no lack of clarity within the standard. While AEP does not entirely object to the concept of explicitly referencing the SOC Program Manual in the requirements of PER-003-1, extreme care should taken to ensure that additional obligations aren't unintentionally implied by generally referring to the entire manual as a whole.

Likes 0	
Dislikes 0	

Response

Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual.

The intent of the SAR DT is not to expand the standard to reflect anything more than the certifications referenced in the NERC System Operator Certification Program Manual not the manual in its entirety.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not believe any clarification is needed. The Purpose states, "To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." No revisions are warranted.	
Likes 0	
Dislikes 0	
Response	
Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. The language listed within this question does not currently align with what is listed within the SAR. We want to confirm that the language proposed does not identify a specific standard revision (i.e. PER-003-1). Furthermore, we propose the footnote references the NERC Personnel Certification Program, as identified within the NERC Rules of Procedure. We propose using this language instead for the footnote, "The NERC certificates referenced in this standard pertain to those identified under the NERC Personnel Certification Program (i.e. NERC System Operator Certification Program)."	

2. We feel the SDT has misunderstood our previous comments regarding the Enhanced Periodic Review of the PER Reliability Standards. The scope of PER-003 is to require registered entities to staff Real-time operating positions with NERC-certified System Operators performing reliability-related tasks. Personnel are certified through an examination process that is dictated by the NERC System Operator Certification Program and governed by the NERC Personnel Certification Governance Committee (PCGC). However, with recent changes to the exam, as identified on the NERC web site (http://www.nerc.com/pa/Train/SysOpCert/Pages/default.aspx), we no longer see a one-to-one set of minimum competencies necessary for eligible candidates to possess in order to take the NERC System Operator Certification exam. This places a compliance burden on applicable entities to demonstrate a reasonable assurance that their NERC-certified System Operators have obtained the necessary competencies, as identified within the PER-003-1 standard. We feel this "chicken-and-egg" problem could be entirely avoided by removing the minimum set of competencies from the standard and only requiring applicable entities to staff Real-time operating positions with NERC-certified System Operators performing reliability-related tasks. This would also provide the NERC PCGC more control over the NERC System Operator Certification Program and not conflict with examination and continuing education requirements posted on the NERC web site.
3. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

1. Thank you for your comment. The language referenced is suggested language provided by the SAR DT. The actual language will be developed by the standard drafting team during the next phase of this project.
2. The SAR DT does not know of any violations of this standard that nessitates the modifications you suggested related to competencies associated with perceived compliance burden. FERC Order 693 paragraph 1396 directed the ERO to include minimum competencies in this standard. Therefore, the scope of the standard is the minimum competencies required to operate the BES as a NERC Certified System Operator (NCSO).

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
The footnote provides necessary clarity.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

We agree that the proposed footnote will provide the necessary clarification, but suggest to change "certifications" to certificates" to conform with the language used in the requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language referenced is suggested language provided by the SAR DT. The actual language will be developed by the standard drafting team during the next phase of this project.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	

No comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The PRT suggests that PER-004-2 be retired based on the identified duplicate requirements. Do you agree that his standard should be retired? If not, please explain in the comment area below.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned there could be a potential reliability gap in retiring PER-004-2 R1. The SAR argues PER-004-2 is duplicative and all requirements are covered in other reliability standards. Texas RE is concerned that without an explicit requirement to be staffed with NERC-certified operators 24/7 the RCs' control centers may not be staffed with adequately trained personnel. Is the SDT's position that	

without the explicit obligation in PER-004-2 R1 that there would be a continuing explicit obligation for RCs to be staffed with NERC-certified operators 24/7? If so, please explain and indicate the specific standard requirements including such compliance responsibility.	
Likes 0	
Dislikes 0	
Response	
The SAR DT determined that a RC maintaining Reliable Operations requires staffing 24/7; which is inherent in an RC fulfilling the compliance obligations for requirements identified on pages 3, 4 and 5 of the SAR. With regards to your comment concerning adequately trained personnel, training requirements are stated in PER-005.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We would like to thank the drafting team for their efforts of pointing out the redundancy associated with this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The NSRF agrees with the PRT recommendation for retirement of PER-004-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	

Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	

This Standard is not applicable to Manitoba Hydro.	
Likes 0	
Dislikes 0	
Response	
Thank you for your clarifying comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
We are not an RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your clarifying comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
PER-004-2 does not apply to BPA as BPA is not registered as a Reliability Coordinator.	
Likes 0	

Dislikes 0	
Response	
Thank you for your clarifying comment.	

3. Do you know of any additional requirements that the PRT has not identified to justify the retirement of PER-004-2? If yes, please identify the standard and requirement in the comment area below.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
PER-004-2 does not apply to BPA as BPA is not registered as a Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Thank you for your clarifying comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
We are not an RC.	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	
This Standard is not applicable to Manitoba Hydro.	
Likes 0	
Dislikes 0	
Response	
Thank you for your clarifying comment.	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first posting of the revised draft standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 2017
SAR posted for comment	June 21, 2017 through July 24, 2017

Anticipated Actions	Date
45-day formal comment period with ballot	December 2017 – January 2017
10-day final ballot	February 2017
Board adoption	May 2017

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-1**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2.

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan – Add link

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	TBD	Added footnote to requirements	Revision
2	TBD	Adopted by Board of Trustees	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first posting of the revised draft standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 2017
SAR posted for comment	June 21, 2017 through July 24, 2017

Anticipated Actions	Date
45-day formal comment period with ballot	December 2017 – January 2017
10-day final ballot	February 2017
Board adoption	May 2017

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-1**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2. In those jurisdictions where regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after Board of Trustees adoption.

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan – Add link

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	TBD	Added footnote to requirements	Revision
2	TBD	Adopted by Board of Trustees	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-02 Operating Personnel Credentials

Requested Approvals

- PER-003-2 Operating Personnel Credentials

Requested Retirements

- PER-003-1 Operating Personnel Credentials
- PER-004-2 Reliability Coordination - Staffing

Applicable Entities

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Effective Date

The effective date for proposed Reliability Standard PER-003-2 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard PER-003-2 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PER-003-2 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standards PER-003-1 and PER-004-2 shall be retired immediately prior to the effective date of the proposed PER-003-2 standard.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications (PER) Standards

Do not use this form for submitting comments. Use the electronic form to submit comments on the **2017-02 PER** project. The electronic form must be submitted by **8 p.m. Eastern, Wednesday, March 7, 2018**.

Documents and information about this project are available on the Project 2017-02 PER page. If you have questions, contact Senior Standards Developer, Darrel Richardson or at (609) 613-1848.

Background

The periodic review project reviewed the following two PER standards.

- PER-003-1 – Operating Personnel Credentials
- PER-004-2 – Reliability Coordination - Staffing

PER-001-0.2 was not reviewed during the periodic review. This standard was approved for retirement under FERC Order 817. Therefore this project only reviewed PER-003-1 and PER-004-2.

The PER periodic review team (PER PRT) used the background information, along with any associated worksheets or reference documents (such as the Independent Expert Review Project report, and Paragraph 81 criteria) to guide a comprehensive review that would result in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the Standard;
2. Recommend revising the Standard; or
3. Recommend retirement of the standard.

The PER PRT developed this Standard Authorization Request (SAR) to implement their recommendations. The SAR proposes to make a minor modification to PER-003-1 and retire PER-004-2. The standard drafting team (SDT) modified the requirements by adding a footnote. Please provide your response to the question listed below along with any detailed comments.

Questions

1. The SDT added a clarifying footnote to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT has written the implementation plan to retire PER-004-2. Do you agree that his standard should be retired? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

Formal Comment Period Open through March 7, 2018
Ballot Pools Forming through February 20, 2018

Now Available

A 45-day formal comment period for the following is open through **8 p.m. Eastern, Wednesday, March 7, 2018**.

- PER-003-2 Operating Personnel Credentials
- PER-003-1 Operating Personnel Credentials – Retirement
- PER-004-2 Reliability Coordination-Staffing – Retirement

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Tuesday, February 20, 2018.** Registered Ballot Body members can join the ballot pools here.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and implementation plan will be conducted February 26 - March 7, 2018.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards | PER-003-2 and Implementation Plan
Comment Period Start Date:	1/22/2018
Comment Period End Date:	3/7/2018
Associated Ballots:	2017-02 Modifications to Performance, Training, and Qualifications Standards Implementation Plan IN 1 OT 2017-02 Modifications to Performance, Training, and Qualifications Standards PER-003-2 IN 1 ST

There were 30 sets of responses, including comments from approximately 97 different people from approximately 76 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT added a clarifying footnote to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

2. The SDT has written the implementation plan to retire PER-004-2. Do you agree that his standard should be retired? If not, please explain in the comment area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
DTE Energy - Detroit Edison Company	Jeffrey DePriest	5		DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE
Northeast Power	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE	Guy V. Zito	Northeast Power	10	NPCC

Coordinating Council						Coordinating Council		
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC

					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Bobby Gray	Board of Public Utilities (BPU) kanas	3	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					J. Scott Williams	City Utilities of Springfield, MO	1,4	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

1. The SDT added a clarifying footnote to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

The clarification should be made in the NERC Glossary of Terms. The use of footnotes to define the terminology could result in different Standards being interpreted differently base on footnoting. Standards may eventually begin to conflict based on how different terms are used in specific context. Though not a major issue for the current project it sets a precedent that opens the door to problems down the road.

Likes 0	
Dislikes 0	

Response

Aimee Harris - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

Adding a footnote to PER-003 to reference the certification program is short sightedness from the Standards Drafting Team. The key words in this standard as well as many others is "System Operator". Itwould be better to redo the System Operator definition in the NERC Glossary of Terms to include "a NERC certified individual" and add the reference to the NERC System Operator Certification Program Manual.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

As stated in our previous comments related to Project 2016-EPR-01, AEP believes the standard as currently written is sufficiently clear in this regard. The current version of the standard states that its purpose is "to ensure that System Operators performing the reliability-related tasks of the

Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." This, coupled with the references to "NERC Reliability Operator certificate" within the requirements themselves, provides a clear and direct correlation to the certification specified within the NERC System Operator Certification Program Manual. As a result, we see no lack of clarity within the standard. While AEP does not entirely object to the concept of explicitly referencing the SOC Program Manual in the requirements of PER-003-1, extreme care should be taken to ensure that additional obligations are not unintentionally implied by generally referring to the entire manual as a whole.

In response to our previously submitted comments, the drafting team states in their July 2017 consideration of comments document that "The intent of the SAR DT is not to expand the standard to reflect anything more than the certifications referenced in the NERC System Operator Certification Program Manual not the manual in its entirety." While we are sure it is not the drafting team's intent that additional obligations be implied, that risk nonetheless remains (say perhaps, when read by an auditor). While AEP does not believe that the proposed clarifying language and footnote is needed, if one is indeed pursued, we suggest instead using *"The NERC* ~~certificates~~ ***certified credentials*** *referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual."*

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SRP believes the current standard does not require additional clarification as to the type of certification required. However, SRP does not have concerns with adding the proposed footnote.

Likes 0	
Dislikes 0	

Response

Theresa Allard - Minnkota Power Cooperative Inc. - 1

Answer	No
Document Name	

Comment

Minnkota would like to sign on the the NERC Standards Review Forum comments as follows:

The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is "minimum competency" passing the NERC exam? Entities cannot prove that a System Operator passed with minimum

competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of “minimum competency” only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, than time, resources and valuable funding will be wasted on opening another Project to address this simple concern.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment

Alliant Energy supports the following comments from the MRO NSRF:

The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is “minimum competency” passing the NERC exam? Entities cannot prove that a System Operator passed with minimum competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of “minimum competency” only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, then time, resources and valuable funding will be wasted on opening another Project to address this simple concern.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment
The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is “minimum competency” passing the NERC exam? Entities cannot prove that a System Operator passed with minimum competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of “minimum competency” only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, than time, resources and valuable funding will be wasted on opening another Project to address this simple concern.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment
changes are minor for TOP’s and just add clarification with a new “footnote”

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	

Comment
The footnote does provide clarity in regards to the specfication of what certificates are being addressed. ***However, PGE has concerns regarding the referencing of documents, in this case a manual, in a footnote, that is controlled outside of the Standard Development process.***

Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Kondziolka - Salt River Project - 3	
Answer	
Document Name	
Comment	
I support the comments submitted by Salt River Project.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	

Dislikes 0	
Response	

2. The SDT has written the implementation plan to retire PER-004-2. Do you agree that his standard should be retired? If not, please explain in the comment area below.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes in order to retire PER-004-2 R2, language should be incorporated into the proposed PER-003-2 requiring each RC to staff their Real-Time operations 24 hrs/day.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
In reviewing the arguments for retirement of PER-004 we are not sure the issue of 24 hours staffing is adequately addressed in the other cited standards. Other standards address "Reliability Coordinator" as an entity, not "Reliability Coordinator Operating Personnel". We believe the drafting team has good reason to retire PER-004-2, and the argument seems intuitive; however, due to enhanced technology, removing the staffing requirements could introduce arguments that 24 X 7 staffing is not required by the standards. It could be further argued that certain activities do not need Certified Operating Personnel oversight because they are automated. Since Reliability Standards have been made mandatory there have been continuous arguments over business authority, Entity v. Operating Personnel, who specifically needs to be certified, and who determines staffing.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
We thank you for the opportunity to comment.	

Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
changes are minor for TOP's and just add clarification with a new "footnote"	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aimee Harris - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates the Standard Drafting Team's (SDT) efforts to implement the Enhanced Periodic Review (EPR) team's recommendations. Texas RE recognizes that there is significant overlap between PER-004-2 and other training Standards, including PER-003 and PER-005. However, Texas RE remains concerned that retiring PER-004-2 R1 could introduce unnecessary ambiguity. Specifically, while other PER and IRO requirements cited by the EPR team as overlapping with PER-004-2 R1 contain similar elements, they do not appear to be as explicit regarding NERC-certification requirements and the adequacy of training in connection with those requirements as existing PER-004-2 R1, which is proposed for retirement. As noted in its response, the SDT relies on PER-003-1 R1 and PER-005-2 R1 to address training issues. While both standards address aspects of training, neither provide an unambiguous obligation for applicable entities to provide adequate training to their personnel in all circumstances. For instance, PER-003-1 R1 provides that "Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators	

who have demonstrated *minimum competency* in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate." (emphasis added). It further specifies Areas of Competency, including "Emergency preparedness and operations." (PER-003-1 R1.1.3).

Under PER-003-1 R1, the sole required task appears to be for System Operators to demonstrate "minimum competency" by obtaining a valid NERC Reliability Operator certificate.

While this requirement overlaps with the "adequate training" requirement set forth in PER-004-2 R1, it does not necessarily cover all training circumstances. By way of example, Texas RE has encountered at least one instance in which an entity's operators possessed NERC certifications, but had not received adequate training for properly implementing an emergency electric curtailment plan. This lack of training exacerbated an emergency condition, prolonging an event. It is unclear whether the language in PER-003-1 R1, with its focus solely on minimal competency demonstrated through the possession of a NERC certification would be broad enough to address circumstances in which an entity's training was demonstrably inadequate for a particular circumstance.

In addition to concerns regarding the possible narrowing of the requirement that an entity possess adequately trained operators, Texas RE remains concerned that the elimination of PER-004-2 R1 may introduce unnecessary ambiguity regarding the requirement to staff Reliability Coordinator Control Centers with NERC-certified operators on a continuous basis. In its Consideration of Comments, the SDT constructs such a requirement by combining the requirement in PER-003-1 R1 that Real-time operating positions by staffed by System Operators with various requirements in the IRO Standard family that the SDT argues requires continuous staffing. However, it is not clear that all Real-Time operating tasks must themselves be performed by a System Operator. For instance, the Real-time Assessment (RTA) definition includes a statement that a "Real-time Assessment may be provided through internal systems or through third-party services." That is, the definition of an RTA appears to permit third-party services to perform the RTA task. As such, it is unclear whether the continuous obligation to perform an RTA correspondingly triggers an obligation to staff a Reliability Coordinator Control Center with NERC-certified System Operators. The SDT should avoid any ambiguity around this requirement by retaining PER-004-2 R1 as currently drafted.

Likes 0	
Dislikes 0	

Response

Robert Kondziolka - Salt River Project - 3

Answer	
Document Name	

Comment

I support the comments submitted by Salt River Project.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards | PER-003-2 and Implementation Plan
Comment Period Start Date:	1/22/2018
Comment Period End Date:	3/7/2018
Associated Ballots:	2017-02 Modifications to Performance, Training, and Qualifications Standards Implementation Plan IN 1 OT 2017-02 Modifications to Performance, Training, and Qualifications Standards PER-003-2 IN 1 ST

There were 30 sets of responses, including comments from approximately 97 different people from approximately 76 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT added a clarifying footnote to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below.

2. The SDT has written the implementation plan to retire PER-004-2. Do you agree that his standard should be retired? If not, please explain in the comment area below.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
DTE Energy - Detroit	Jeffrey DePriest	5		DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Edison Company					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Terry Bilke	MISO	2	MRO
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Charles Yeung	SPP	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Bobby Gray	Board of Public Utilities (BPU) kanas	3	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					J. Scott Williams	City Utilities of Springfield, MO	1,4	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

1. *The SDT added a clarifying footnote to all of the requirements in PER-003-1. The PRT is suggesting that the footnote state the following: "The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual." Do you agree that this footnote would provide the necessary clarity? If not, please explain in the comment area below*.
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment
The clarification should be made in the NERC Glossary of Terms. The use of footnotes to define the terminology could result in different Standards being interpreted differently base on footnoting. Standards may eventually begin to conflict based on how different terms are used in specific context. Though not a major issue for the current project it sets a precedent that opens the door to problems down the road.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. Footnotes are an available tool to provide clarity in several of the existing FERC approved standards.
Aimee Harris - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

Adding a footnote to PER-003 to reference the certification program is short sightedness from the Standards Drafting Team. The key words in this standard as well as many others is "System Operator". Itwould be better to redo the System Operator definition in the NERC Glossary of Terms to include "a NERC certified individual" and add the reference to the NERC System Operator Certification Program Manual.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. Footnotes are an available tool to provide clarity in several of the existing FERC approved standards. Modification of the definition of System Operator is outside the scope of this project.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As stated in our previous comments related to Project 2016-EPR-01, AEP believes the standard as currently written is sufficiently clear in this regard. The current version of the standard states that its purpose is “to ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.” This, coupled with the references to “NERC Reliability Operator certificate” within the requirements themselves, provides a clear and direct correlation to the certification specified within the NERC System Operator Certification Program Manual. As a result, we see no lack of clarity within the standard. While AEP does not entirely object to the concept of explicitly referencing the SOC Program Manual in the requirements of PER-003-1, extreme care should be taken to ensure that additional obligations are not unintentionally implied by generally referring to the entire manual as a whole.	

In response to our previously submitted comments, the drafting team states in their July 2017 consideration of comments document that "The intent of the SAR DT is not to expand the standard to reflect anything more than the certifications referenced in the NERC System Operator Certification Program Manual not the manual in its entirety." While we are sure it is not the drafting team's intent that additional obligations be implied, that risk nonetheless remains (say perhaps, when read by an auditor). While AEP does not believe that the proposed clarifying language and footnote is needed, if one is indeed pursued, we suggest instead using *"The NERC* ~~certificates~~ ***certified credentials*** *referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual."*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. The SDT does not believe that your suggested alternative language provides any additional clarity.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes the current standard does not require additional clarification as to the type of certification required. However, SRP does not have concerns with adding the proposed footnote.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	
Comment	
Minnkota would like to sign on the the NERC Standards Review Forum comments as follows: The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is "minimum competency" passing the NERC exam? Entities cannot prove that a System Operator passed with minimum competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of "minimum competency" only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, than time, resources and valuable funding will be wasted on opening another Project to address this simple concern.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. However, modification of the areas of competency within the standard is outside the scope of this project. The FERC Order 693 contained a directive that the PER-003 standard include minimum competencies. Areas of competency as used in this standard represent the most efficient and effective method for meeting the FERC directive.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the following comments from the MRO NSRF: The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is "minimum competency" passing the NERC exam? Entities cannot prove that a System Operator passed with minimum competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of "minimum competency" only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, then time, resources and valuable funding will be wasted on opening another Project to address this simple concern.	
Likes 0	

Dislikes 0	

Response
Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. However, modification of the areas of competency within the standard is outside the scope of this project. The FERC Order 693 contained a directive that the PER-003 standard include minimum competencies. Areas of competency as used in this standard represent the most efficient and effective method for meeting the FERC directive.

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF agrees with the additional foot note but disagrees with the Areas of Competency in R1, R2 and R3. RCs, BAs and TOPs have no control over the Areas of Competency within a NERC Certificate exam. The exam is based on other mechanisms (the PCGC) that BAs, TOPs and RCs have no control over. Is “minimum competency” passing the NERC exam? Entities cannot prove that a System Operator passed with minimum competency, the components under past 1.1, 2.1, and 3.1. The written Measures do not indicate what level of “minimum competency” only that NERC certificate (or NERC number) is required. The Areas of Competency do not support the reliability BES and is a legacy issue from years ago. The Areas of Competency are strictly within a test that Registered Entities have no control over. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. The NSRF agrees that no one has been found non-compliant and this is a simple item to satisfy during an audit. But we are looking to gain efficiencies everywhere we can, and this is some low hanging fruit that can be corrected with a simple stroke of the SDT pen. The NSRF agrees that NERC Certification is required for RCs, TOPs and BAs and do not wish for this Standard to be retired (PER-003-1). There is a current NERC Certification survey that asks many questions about NERC Certification. That is being attributed to the PCGC and not this SDT. The SDT has the power to gain one more efficiency for the Applicable Entities of PER-003-1. The NSRF recommends that the Areas of Competency within R1, R2 and R3 be removed since this Project is currently active. If the SDT does not move forward with this request, than time, resources and valuable funding will be wasted on opening another Project to address this simple concern.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Industry response and feedback received from this posting and the PRT recommendation posting reaffirms the recommendation to add a footnote to provide clarity as to the connection between the Standard and the NERC System Operator Certification Program Manual. However, modification of the areas of competency within the standard is outside the scope of this project. The FERC Order 693 contained a directive that the PER-003 standard include minimum competencies. Areas of competency as used in this standard represent the most efficient and effective method for meeting the FERC directive.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
changes are minor for TOP's and just add clarification with a new "footnote"	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
The footnote does provide clarity in regards to the specfication of what certificates are being addressed.	

However, PGE has concerns regarding the referencing of documents, in this case a manual, in a footnote, that is controlled outside of the Standard Development process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Robert Kondziolka - Salt River Project - 3	
Answer	
Document Name	
Comment	
I support the comments submitted by Salt River Project.	
Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

2. The SDT has written the implementation plan to retire PER-004-2. Do you agree that his standard should be retired? If not, please explain in the comment area below.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes in order to retire PER-004-2 R2, language should be incorporated into the proposed PER-003-2 requiring each RC to staff their Real-Time operations 24 hrs/day.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT does not believe that it is necessary to include specific language in PER-003 requiring an RC to staff 24/7 as it is inherent for an RC to fulfill its compliance obligations for requirements identified on pages 3, 4 and 5 of the SAR.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
In reviewing the arguments for retirement of PER-004 we are not sure the issue of 24 hours staffing is adequately addressed in the other cited standards. Other standards address "Reliability Coordinator" as an entity, not "Reliability Coordinator Operating Personnel". We believe the drafting team has good reason to retire PER-004-2, and the argument seems intuitive; however, due to enhanced technology,	

removing the staffing requirements could introduce arguments that 24 X 7 staffing is not required by the standards. It could be further argued that certain activities do not need Certified Operating Personnel oversight because they are automated. Since Reliability Standards have been made mandatory there have been continuous arguments over business authority, Entity v. Operating Personnel, who specifically needs to be certified, and who determines staffing.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that it is not necessary to maintain PER-004 that specifically requires an RC to staff 24/7 as it is inherent for an RC to fulfill its compliance obligations for requirements identified on pages 3, 4 and 5 of the SAR.	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
We thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

changes are minor for TOP's and just add clarification with a new "footnote"	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE	
Answer	Yes
Document Name	
Comment	
Thank you for your affirmative response.	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Douglas Johnson - American Transmission Company, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aimee Harris - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your affirmative response.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	

Texas RE appreciates the Standard Drafting Team's (SDT) efforts to implement the Enhanced Periodic Review (EPR) team's recommendations. Texas RE recognizes that there is significant overlap between PER-004-2 and other training Standards, including PER-003 and PER-005. However, Texas RE remains concerned that retiring PER-004-2 R1 could introduce unnecessary ambiguity. Specifically, while other PER and IRO requirements cited by the EPR team as overlapping with PER-004-2 R1 contain similar elements, they do not appear to be as explicit regarding NERC-certification requirements and the adequacy of training in connection with those requirements as existing PER-004-2 R1, which is proposed for retirement.

As noted in its response, the SDT relies on PER-003-1 R1 and PER-005-2 R1 to address training issues. While both standards address aspects of training, neither provide an unambiguous obligation for applicable entities to provide adequate training to their personnel in all circumstances. For instance, PER-003-1 R1 provides that "Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated *minimum competency* in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate." (emphasis added). It further specifies Areas of Competency, including "Emergency preparedness and operations." (PER-003-1 R1.1.3).

Under PER-003-1 R1, the sole required task appears to be for System Operators to demonstrate "minimum competency" by obtaining a valid NERC Reliability Operator certificate.

While this requirement overlaps with the "adequate training" requirement set forth in PER-004-2 R1, it does not necessarily cover all training circumstances. By way of example, Texas RE has encountered at least one instance in which an entity's operators possessed NERC certifications, but had not received adequate training for properly implementing an emergency electric curtailment plan. This lack of training exacerbated an emergency condition, prolonging an event. It is unclear whether the language in PER-003-1 R1, with its focus solely on minimal competency demonstrated through the possession of a NERC certification would be broad enough to address circumstances in which an entity's training was demonstrably inadequate for a particular circumstance.

In addition to concerns regarding the possible narrowing of the requirement that an entity possess adequately trained operators, Texas RE remains concerned that the elimination of PER-004-2 R1 may introduce unnecessary ambiguity regarding the requirement to staff Reliability Coordinator Control Centers with NERC-certified operators on a continuous basis. In its Consideration of Comments, the SDT constructs such a requirement by combining the requirement in PER-003-1 R1 that Real-time operating positions by staffed by System

Operators with various requirements in the IRO Standard family that the SDT argues requires continuous staffing. However, it is not clear that all Real-Time operating tasks must themselves be performed by a System Operator. For instance, the Real-time Assessment (RTA) definition includes a statement that a "Real-time Assessment may be provided through internal systems or through third-party services." That is, the definition of an RTA appears to permit third-party services to perform the RTA task. As such, it is unclear whether the continuous obligation to perform an RTA correspondingly triggers an obligation to staff a Reliability Coordinator Control Center with NERC-certified System Operators. The SDT should avoid any ambiguity around this requirement by retaining PER-004-2 R1 as currently drafted.	
Likes 0	
Dislikes 0	
Response	
The SDT believes that it is not necessary to maintain PER-004 that specifically requires an RC to staff 24/7 as it is inherent for an RC to fulfill its compliance obligations for requirements identified on pages 3, 4 and 5 of the SAR. The FERC Order 693 contained a directive that the PER-003 standard include minimum competencies. Areas of competency as used in this standard represent the most efficient and effective method for meeting the FERC directive. PER-005 requires individuals to receive training and verification of competency.	
Robert Kondziolka - Salt River Project - 3	
Answer	
Document Name	
Comment	
I support the comments submitted by Salt River Project.	
Likes 0	
Dislikes 0	

Response

End of Report

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Standards Announcement

Reminder

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

Initial Ballots Open through March 7, 2018

Now Available

The initial ballots for **PER-003-2 Operating Personnel Credentials** and the associated implementation plan are open through **8 p.m. Eastern, Wednesday, March 7, 2018.**

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience difficulties navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

Formal Comment Period Open through March 7, 2018
Ballot Pools Forming through February 20, 2018

Now Available

A 45-day formal comment period for the following is open through **8 p.m. Eastern, Wednesday, March 7, 2018**.

- PER-003-2 Operating Personnel Credentials
- PER-003-1 Operating Personnel Credentials – Retirement
- PER-004-2 Reliability Coordination-Staffing – Retirement

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Tuesday, February 20, 2018.** Registered Ballot Body members can join the ballot pools here.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and implementation plan will be conducted February 26 - March 7, 2018.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/126)
Ballot Name: 2017-02 Modifications to Performance, Training, and Qualifications Standards PER-003-2 IN 1 ST
Voting Start Date: 2/26/2018 12:01:00 AM
Voting End Date: 3/7/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 208
Total Ballot Pool: 257
Quorum: 80.93
Weighted Segment Value: 97.5

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	70	1	52	0.963	2	0.037	0	2	14
Segment: 2	7	0.4	4	0.4	0	0	0	0	3
Segment: 3	55	1	43	0.956	2	0.044	0	2	8
Segment: 4	13	1	10	1	0	0	0	0	3
Segment: 5	59	1	40	0.952	2	0.048	0	3	14
Segment: 6	43	1	34	0.971	1	0.029	0	1	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	257	6.3	192	6.142	7	0.158	0	9	49

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	JEA	Ted Hobson		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Aaron Austin		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jamie Lynn Bussin	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Previous 1 Next

Showing 1 to 257 of 257 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/126)
Ballot Name: 2017-02 Modifications to Performance, Training, and Qualifications Standards Implementation Plan IN 1 OT
Voting Start Date: 2/26/2018 12:01:00 AM
Voting End Date: 3/7/2018 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 204
Total Ballot Pool: 251
Quorum: 81.27
Weighted Segment Value: 98.91

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	68	1	49	0.98	1	0.02	0	4	14
Segment: 2	7	0.4	4	0.4	0	0	0	0	3
Segment: 3	53	1	40	0.976	1	0.024	0	4	8
Segment: 4	13	1	10	1	0	0	0	0	3
Segment: 5	57	1	40	0.976	1	0.024	0	4	12
Segment: 6	43	1	34	1	0	0	0	2	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	251	6.3	186	6.231	3	0.069	0	15	47

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	JEA	Ted Hobson		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Aaron Austin		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jamie Lynn Bussin	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 251 of 251 entries

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first posting of the revised draft standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 2017
SAR posted for comment	June 21, 2017 through July 24, 2017

Anticipated Actions	Date
45-day formal comment period with ballot	December 2017 – January 2017
10-day final ballot	February 2017
Board adoption	May 2017

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-1**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2.

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan – Add link

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	TBD	Added footnote to requirements	Revision
2	TBD	Adopted by Board of Trustees	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first posting of the revised draft standard.

Completed Actions	Date
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SAR posted for comment	June 21, 2017 through July 24, 2017

Anticipated Actions	Date
45-day formal comment period with ballot	December 2017 – January 2017
10-day final ballot	February 2017
Board adoption	May 2017

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-1**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Balancing Authority

5. **Effective Date:** See Implementation Plan for standard PER-003-2. In those jurisdictions where regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after Board of Trustees adoption.

B. Requirements and Measures

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)][(2)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

[2] The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M3. Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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	N/A	The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan – Add link

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	TBD	Added footnote to requirements	Revision
2	TBD	Adopted by Board of Trustees	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-02 Operating Personnel Credentials

Requested Approvals

- PER-003-2 Operating Personnel Credentials

Requested Retirements

- PER-003-1 Operating Personnel Credentials
- PER-004-2 Reliability Coordination - Staffing

Applicable Entities

- Reliability Coordinator
- Transmission Operator
- Balancing Authority

Effective Date

The effective date for proposed Reliability Standard PER-003-2 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard PER-003-2 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PER-003-2 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standards PER-003-1 and PER-004-2 shall be retired immediately prior to the effective date of the proposed PER-003-2 standard.

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Standards Announcement

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

Final Ballots Open through April 12, 2018

Now Available

Final ballots for the following are open through **8 p.m. Eastern, Thursday, April 12, 2018**.

- PER-003-2 Operating Personnel Credentials
- PER-003-1 Operating Personnel Credentials – Retirement
- PER-004-2 Reliability Coordination-Staffing – Retirement

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience difficulties navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2017-02 Modifications to Performance, Training, and Qualifications Standards PER-003-2 FN 2 ST
Voting Start Date: 4/3/2018 9:59:08 AM
Voting End Date: 4/12/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 218
Total Ballot Pool: 257
Quorum: 84.82
Weighted Segment Value: 96.64

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	70	1	54	0.947	3	0.053	0	1	12
Segment: 2	7	0.4	4	0.4	0	0	0	0	3
Segment: 3	55	1	44	0.936	3	0.064	0	1	7
Segment: 4	13	1	10	1	0	0	0	0	3
Segment: 5	59	1	45	0.957	2	0.043	0	3	9
Segment: 6	43	1	36	0.947	2	0.053	0	0	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	257	6.3	202	6.088	10	0.212	0	6	39

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	JEA	Ted Hobson		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Aaron Austin		Negative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Negative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jamie Lynn Bussin	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 257 of 257 entries

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BALLOT RESULTS

Ballot Name: 2017-02 Modifications to Performance, Training, and Qualifications Standards Implementation Plan FN 2 OT
Voting Start Date: 4/3/2018 10:00:31 AM
Voting End Date: 4/12/2018 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 213
Total Ballot Pool: 251
Quorum: 84.86
Weighted Segment Value: 97.88

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	68	1	50	0.962	2	0.038	0	3	13
Segment: 2	7	0.4	4	0.4	0	0	0	0	3
Segment: 3	53	1	41	0.953	2	0.047	0	3	7
Segment: 4	13	1	10	1	0	0	0	0	3
Segment: 5	57	1	45	0.978	1	0.022	0	4	7
Segment: 6	43	1	36	0.973	1	0.027	0	1	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

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Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	251	6.3	195	6.166	6	0.134	0	12	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	JEA	Ted Hobson		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Aaron Austin		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		None	N/A
3	Austin Energy	W. Dwayne Preston		None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Negative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jamie Lynn Bussin	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 251 of 251 entries

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Exhibit E

Standard Drafting Team Roster for Project 2017-02

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Drafting Team Roster

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards

	Name	Entity
Members	Patty Metro	National Rural Electric Cooperative Association
	Lauri Jones	Pacific Gas and Electric Company
	Heather Morgan	EDP Renewables North America LLC
	Jeffrey Sunvick	Western Area Power Administration
	Jimmy Womack	Southwest Power Pool
	Brad Perrett	Minnesota Power
	Carolyn White-Wilson	Duke Energy
	Donald Wallin	PJM Interconnection
	Danny W. Johnson	Excel Energy
NERC Staff	Darrel Richardson, Principal Technical Advisor	North American Electric Reliability Corporation
	Nina Jenkins-Johnston, Senior Counsel	North American Electric Reliability Corporation

164 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM18-2-000; Order No. 848]

Cyber Security Incident Reporting Reliability Standards

(Issued July 19, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) directs the North American Electric Reliability Corporation (NERC) to develop and submit modifications to the NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the bulk electric system (BES).

DATES: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

FOR FURTHER INFORMATION CONTACT:

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(202) 502-6704
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Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6840
Kevin.Ryan@ferc.gov

SUPPLEMENTARY INFORMATION:

164 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Kevin J. McIntyre, Chairman;
Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

Cyber Security Incident Reporting Reliability Standards Docket No. RM18-2-000

ORDER NO. 848

FINAL RULE

(Issued July 19, 2018)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA), the Commission directs the North American Electric Reliability Corporation (NERC) to develop and submit modifications to the NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES.[1] The Commission directs NERC to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible

[1] 16 U.S.C. 824o(d)(5). The NERC Glossary of Terms Used in NERC Reliability Standards (June 12, 2018) (NERC Glossary) defines a Cyber Security Incident as "A malicious act or suspicious event that: Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System."

entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS).[2]

2. In the NOPR, the Commission observed that Cyber Security Incidents are presently reported by responsible entities in accordance with Reliability Standard CIP-008-5 (Cyber Security – Incident Reporting and Response Planning).[3] However, under the definition of Reportable Cyber Security Incident in Reliability Standard CIP-008-5, responsible entities must only report Cyber Security Incidents if they have "compromised or disrupted one or more reliability tasks." The Commission explained that the current reporting threshold may understate the true scope of cyber-related threats facing the Bulk-Power System, particularly given the lack of any reportable incidents in 2015 and 2016. To improve awareness of existing and future cyber security threats and potential vulnerabilities, the Commission proposed to direct that NERC develop and submit modifications to the existing Reliability Standards to augment the reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES.

3. As discussed in detail below, the Commission adopts the NOPR proposal. The Commission's directive in this Final Rule consists of four elements intended to augment

[2] The NERC Glossary defines "ESP" as "[t]he logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." The NERC Glossary defines "EACMS" as "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems."

[3] *Cyber Security Incident Reporting Reliability Standards*, Notice of Proposed Rulemaking, 82 FR 61,499 (Dec. 28, 2017), 161 FERC ¶ 61,291, P 1 (2017) (NOPR).

the current Cyber Security Incident reporting requirement: (1) responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; (3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and (4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT). Further, NERC must file an annual, public, and anonymized summary of the reports with the Commission.

4. As discussed below, after considering the comments submitted in response to the NOPR, we conclude that the proposed directive to augment the current reporting requirement for Cyber Security Incidents is appropriate to carry out FPA section 215. As NERC recognizes in its NOPR comments, "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities[,] … would create a more extensive baseline understanding of the nature of cyber security threats and vulnerabilities[,] … [and] is consistent with recommendations in

NERC's 2017 State of Reliability Report."[4] Our directive is intended to result in a measured broadening of the existing reporting requirement in Reliability Standard CIP-008-5, consistent with NERC's recommendation, rather than a wholesale change in cyber incident reporting that supplants or otherwise chills voluntary reporting, as some commenters maintain. Indeed, as NERC contends, we believe that the new "baseline understanding, coupled with the additional context from voluntary reports received by the E-ISAC, [will] allow NERC and the E-ISAC to share that information broadly through the electric industry to better prepare entities to protect their critical infrastructure."[5]

5. We address in the discussion below concerns raised by commenters regarding elements of the Commission's directive and the burdens the directive might impose if NERC develops requirements that are overly broad. At the outset, we agree with NERC that "because certain requirements in the CIP Reliability Standards already require entities to track data on compromises or attempts to compromise the ESP or EACMS, the additional burden to report that data appears reasonable."[6] And we do not believe that complying with the augmented reporting requirements that we direct here would be any more burdensome to industry than the alternative, responding to a perpetual data or information request to collect the same information pursuant to Section 1600 of the NERC Rules of Procedure. To ensure that the burden is reasonable with respect to

[4] NERC Comments at 4.

[5] *Id.*

[6] *Id.* at 8 (citing Reliability Standard CIP-005-5 (Cyber Security — Electronic Security Perimeter(s)) and Reliability Standard CIP-007-6 (Cyber Security — System Security Management)).

including EACMS in the augmented reporting requirement, NERC should develop requirements based on the function of the EACMS and the nature of the attempted compromise or successful intrusion. Similarly, as discussed below, NERC should develop reporting timelines for Cyber Security Incidents that are commensurate with the adverse or attempted adverse impact to the BES that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES.[7] Prioritizing incident reporting will allow responsible entities to devote resources to reporting the most significant Cyber Security Incidents faster than less significant events. With this guidance, we believe that the standard drafting team, in the first instance, is in the best position to develop the specific elements of the directed Reliability Standard requirements.

6. We have considered comments submitted by NERC and others recommending that broadened Cyber Security Incident reporting should be implemented through a request for information or data pursuant to Section 1600 of the NERC Rules of Procedure instead of through Reliability Standard requirements. However, on balance, we believe that broadened mandatory reporting pursuant to Reliability Standard requirements as opposed to a standing data request is more aligned with the seriousness and magnitude of the

[7] The NERC Glossary defines BES Cyber System as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity." Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). Reliability Standard CIP-002-5.1a (Cyber Security System Categorization) provides a "tiered" approach to cybersecurity requirements, based on classifications of high, medium and low impact BES Cyber Systems.

current threat environment, and more likely to improve awareness of existing and future cyber security threats and potential vulnerabilities. Four main reasons inform our decision. First, a new or modified Reliability Standard will ensure that the desired goals of our directive are met because the Commission will have the ability to review and ultimately approve the standard, as opposed to the opportunity for informal review that the Commission would have of a data request under ROP Section 1600. Second, the Commission has well-defined authority and processes under section 215(e) of the FPA to audit and enforce compliance with a Reliability Standard. Third, we do not anticipate that there will be a need to change the parameters of the Cyber Security Incident report for EACMS because the parameters that we direct below are based on five static functions of EACMS and are not technology specific, so the potential flexibility provided by a Section 1600 data request may not be significantly beneficial. Finally, collecting data through a Reliability Standard is consistent with existing practices; responsible entities are currently required to maintain the types of information that would lead to a reportable Cyber Security Incident pursuant to Reliability Standard CIP-007-6, Requirement R4.1. Nonetheless, should future events require an expedited change in data collection or should NERC desire to collect data outside the scope of the proposed Reliability Standard, NERC could then use the Section 1600 process to supplement information reported under a mandatory Reliability Standard.

7. Accordingly, pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop modifications to the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt

to compromise, a responsible entity's ESP or associated EACMS, as well as modifications to specify the required information in Cyber Security Incident reports, their dissemination, and deadlines for filing reports. We direct NERC to submit the directed modifications within six-months of the effective date of this Final Rule.

I. Background

A. Section 215 and Mandatory Reliability Standards

8. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[8] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[9] and subsequently certified NERC.[10]

B. Notice of Proposed Rulemaking

9. On December 21, 2017, the Commission issued a NOPR proposing to direct that NERC develop enhanced Cyber Security Incident reporting requirements. Specifically, pursuant to section 215(d)(5) of the FPA, the NOPR proposed to direct NERC to develop

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[8] *Id.*

[9] *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).

[10] *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).

modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. The proposed directive was based in part on a lack of Reportable Cyber Security Incidents in 2015 and 2016, and NERC's assessment in the 2017 State of Reliability Report that "[w]hile there were no reportable cyber security incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low."[11] In addition, the NOPR stated that it agreed with the recommendation by NERC in the 2017 State of Reliability Report to "redefine reportable incidents to be more granular and include zero-consequence incidents that might be precursors to something more serious."[12]

10. In justifying the proposed inclusion of ESPs and associated EACMS within the scope of the enhanced Cyber Security Incident requirement, the NOPR stated that the purpose of an ESP is to manage electronic access to BES Cyber Systems to support the protection of the BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.[13] In addition, the NOPR explained that EACMS, which include, for example, firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems, control electronic access into the ESP

[11] NOPR, 161 FERC ¶ 61,291 at P 28 (citing 2017 NERC State of Reliability Report at 4).

[12] *Id.* P 29 (citing 2017 NERC State of Reliability Report at 4).

[13] *See id.* P 33 (citing Reliability Standard CIP-005-5 (Cyber Security – Electronic Security Perimeter(s)).

and play a significant role in the protection of high and medium impact BES Cyber Systems.[14] The NOPR indicated further that, once an EACMS is compromised, an attacker could more easily enter the ESP and effectively control the BES Cyber System or Protected Cyber Asset.

11. The NOPR discussed the scope of the present Cyber Security Incident reporting requirement. The NOPR observed that Reliability Standard CIP-008-5, Requirement R1.2 currently requires that each responsible entity shall document one or more Cyber Security Incident Plan(s) with one or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident. And where a Cyber Security Incident is determined to qualify as a Reportable Cyber Security Incident, the NOPR explained that responsible entities are required to notify the E-ISAC with initial notification within one hour from the determination of a Reportable Cyber Security Incident. The NOPR stated, however, that the NERC Glossary defines a Reportable Cyber Security Incident as "[a] Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity." The NOPR indicated that the definition of Reportable Cyber Security Incident, insofar as it excludes unsuccessful attempts to compromise or disrupt a responsible entity's core activities, is thus more narrow than the definition of "cybersecurity incident" in FPA section 215(a)(8), which

[14] *See id.* (citing Reliability Standard CIP-002-5.1 (Cyber Security – BES Cyber System Categorization), Background at 6; Reliability Standard CIP-007-6 (Cyber Security – System Security Management), Background at 4).

encompasses "a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the bulk power system."[15]

12. The NOPR stated that altering the Cyber Security Incident reporting threshold to require reporting of attempts to compromise, instead of only successful compromises, is consistent with information already logged by registered entities pursuant to current monitoring requirements in the Reliability Standards. The NOPR explained that Reliability Standard CIP-007-6, Requirement R4.1, mandates logging of detected successful login attempts, detected failed access attempts, and failed login attempts, and the Guidelines and Technical Basis for Requirement R4.1 states that events should be logged even if access attempts were blocked or otherwise unsuccessful.[16]

13. In addition to modifying the reporting threshold, the NOPR proposed to direct NERC to modify the Reliability Standards to specify the required information in Cyber Security Incident reports to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information, as well as the deadlines for submitting a report. Specifically, the NOPR proposed that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack

[15] 16 U.S.C. 824o(a)(8).

[16] *See* Reliability Standard CIP-007-6 (Cyber Security – Systems Security Management), Requirement R4.1.

vector used to achieve or attempt to achieve the Cyber Security Incident; and (3) the level of intrusion achieved or attempted by the Cyber Security Incident. The NOPR explained that knowledge of these attributes regarding a specific Cyber Security Incident will improve awareness of cyber threats to BES reliability. The NOPR also noted that the proposed attributes are the same as attributes already used by DHS for its multi-sector reporting and summarized by DHS in an annual report.[17]

14. The NOPR also proposed to continue to require that Cyber Security Incident reports be sent to the E-ISAC instead of the Commission, but the NOPR proposed to require that such reports also be sent to ICS-CERT and that NERC file with the Commission an annual, public, and anonymized summary of such reports.

15. Finally, the NOPR sought comment on potential alternatives to modifying the mandatory reporting requirements in the NERC Reliability Standards. Specifically, the NOPR sought comment on whether a request for data or information pursuant to Section 1600 of the NERC Rules of Procedure would effectively address the reporting gap and current lack of awareness of cyber-related incidents among NERC, responsible entities and the Commission, and satisfy the goals of the proposed directive.

II. Discussion

16. Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit modifications to the NERC Reliability Standards to augment current mandatory reporting of Cyber Security Incidents, including incidents

[17] NOPR, 161 FERC ¶ 61,291 at P 38 (citing 2016 ICS-CERT Year in Review, https://ics-cert.us-cert.gov/Year-Review-2016).

that might facilitate subsequent efforts to harm the reliable operation of the BES. We direct NERC, subject to the discussion below, to develop and submit Reliability Standard requirements that: (1) require responsible entities to report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) specify the required information in Cyber Security Incident reports; (3) establish deadlines for filing Cyber Security Incident reports that are commensurate with incident severity; and (4) require that Cyber Security Incident reports be sent to ICS-CERT, in addition to E-ISAC, and that NERC file with the Commission an annual, public, and anonymized summary of such reports.

17. Below, we discuss the following matters: (A) the need for broadened mandatory Cyber Security Incident reporting; (B) the threshold for a reportable Cyber Security Incident; (C) the appropriate procedural approach to augment Cyber Security Incident reporting, i.e., new or modified Reliability Standards versus a NERC data request to applicable entities; (D) the content and timing of Cyber Security Incident reports; and (E) other issues.

A. Need for Broadened Mandatory Cyber Security Incident Reporting

1. NOPR

18. In the NOPR, the Commission indicated that cyber-related event reporting is currently addressed in Reliability Standard CIP-008-5, Requirement R1.2, which requires that each responsible entity shall document one or more Cyber Security Incident Plan(s) with one or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident. The NOPR noted that a Cyber Security Incident is

defined in the NERC Glossary as: "A malicious act or suspicious event that: (1) compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or (2) disrupts, or was an attempt to disrupt, the operation of a BES Cyber System."

19. The Commission further explained that where a cyber-related event is determined to qualify as a Reportable Cyber Security Incident**,** responsible entities are required to notify the E-ISAC with initial notification to be made within one hour from the determination of a Reportable Cyber Security Incident.[18] However, the NOPR observed that a Reportable Cyber Security Incident is defined more narrowly in the NERC Glossary than a Cyber Security Incident because the former requires that the incident result in the compromise or disruption of one or more reliability tasks of a functional entity. As the Commission explained, in order for a cyber-related event to be considered reportable under the existing CIP Reliability Standards, it must compromise or disrupt a core activity (e.g., reliability task) of a responsible entity that is intended to maintain BES reliability.[19] Therefore, under these definitions, unsuccessful attempts to compromise or

[18] *See* Reliability Standard CIP-008-5 (Cyber Security – Incident Reporting and Response Planning), Requirement R1, Part 1.2. This requirement pertains to high impact BES Cyber Systems and medium impact BES Cyber Systems.

[19] The NERC Functional 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. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions)." NERC, Reliability Functional Model: Function Definitions and Functional

disrupt a responsible entity's core activities are not subject to the current reporting requirements in Reliability Standard CIP-008-5 or elsewhere in the CIP Reliability Standards.

20. The NOPR explained that recent NERC State of Reliability Reports indicate that there were no Reportable Cyber Security Incidents in 2015 and 2016. The NOPR also highlighted NERC's conclusion that "[w]hile there were no reportable cyber security incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low."[20] The NOPR contrasted the results reported in the NERC reports with the 2016 annual summary of the Department of Energy's (DOE) Electric Disturbance Reporting Form OE-417, which contained four cybersecurity incidents reported in 2016; two suspected cyber attacks and two actual cyber attacks.[21] Moreover, the NOPR noted that ICS-CERT responded to fifty-nine cybersecurity incidents within the Energy Sector in 2016.[22]

21. Based on the comparison of information reported by NERC, DOE, and ICS-CERT, the NOPR concluded that the current reporting threshold in Reliability Standard

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Entities, Version 5 at 7 (November 2009), http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf.

[20] 2017 NERC State of Reliability Report at 4.

[21] 2016 DOE Electric Disturbance Events (OE-417) Annual Summary Archives, https://www.oe.netl.doe.gov/OE417_annual_summary.aspx.

[22] ICS-CERT cybersecurity incident statistics for the Energy Sector combine statistics from the electric subsector and the oil and natural gas subsector. ICS-CERT does not break out the cybersecurity incidents that only impact the electric subsector. 2016 ICS-CERT Year in Review, https://ics-cert.us-cert.gov/Year-Review-2016.

CIP-008-5 may not reflect the true scope and scale of cyber-related threats facing responsible entities. In particular, the NOPR raised a concern that the disparity in the reporting of cyber-related incidents under existing reporting requirements, in particular the lack of any incidents reported to NERC in 2015 and 2016, suggests a gap in the current reporting requirements. The NOPR highlighted the fact that this concern is echoed in the 2017 NERC State of Reliability Report, which includes a recommendation that NERC and industry should "redefine reportable incidents to be more granular and include zero-consequence incidents that might be precursors to something more serious."[23] Agreeing with NERC's recommendation in the 2017 State of Reliability report, the NOPR proposed to direct NERC to address the apparent gap in cyber incident reporting.

2. Comments

22. NERC supports improving the reporting of Cyber Security Incidents, stating that "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities."[24] NERC maintains that enhanced reporting "would create a more extensive baseline understanding of the nature of cyber security threats and vulnerabilities."[25] NERC notes that broadening the scope of Cyber Security Incident reporting "is consistent with recommendations in NERC's 2017 State

[23] 2017 NERC State of Reliability Report at 4.

[24] NERC Comments at 4.

[25] *Id.* at 4.

of Reliability Report."[26] While NERC recognizes the need for enhanced Cyber Security Incident reporting, as discussed in the following sections, NERC does not support all aspects of the NOPR, including requiring enhanced cyber incident reporting through a modified Reliability Standard.

23. BPA, ITC, IRC, NYPSC, and NRG also support the NOPR proposal to direct NERC to address the gap in reporting Cyber Security Incidents. As noted by BPA, the current definition of Reportable Cyber Security Incident only addresses successful attempts to compromise or disrupt operations and, therefore, "a broader definition of a Reportable Cyber Security incident is warranted" because "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[27] BPA, ITC, and IRC raise concerns, however, regarding the risk of over-reporting. IRC states that the proposed requirement to report all attempts to compromise an ESP or associated EACMS "needs further clarification."[28] BPA states that any new reporting requirement "must ensure that the information reported is useful and does not result in under and over reporting of information."[29] NRG recommends that the term "attempt" should be clarified (i.e., as a more serious risk than a port scan) and "should be

[26] *Id.* at 4.

[27] BPA Comments at 3.

[28] IRC Comments at 1.

[29] BPA Comments at 3.

provided in technical guidance or glossary definition relating to the context of [the] existing NERC glossary term: Cyber Security Incident."[30]

24. EEI/NRECA, Trade Associations, APS, Chamber, EnergySec, Eversource, Idaho Power, and LPPC do not support the NOPR proposal to direct NERC to address the gap in reporting Cyber Security Incidents. EEI/NRECA, Trade Associations, and Chamber suggest that the Commission support existing voluntary reporting practices as opposed to mandating the reporting of Cyber Security Incidents through the CIP Reliability Standards. EEI/NRECA state that "[s]ignificant resources from responsible entities and government are engaged in […] partnerships" to share threat and vulnerability information.[31] EEI/NRECA argue that "[m]andating such sharing will overlap with these voluntary efforts and may harm the partnerships and ability of the programs to enhance cybersecurity for the electric grid."[32] In addition, EEI/NRECA state that mandating Cyber Security Incident reporting "may weaken the ability of electric companies to participate in these [voluntary reporting] programs by shifting their focus to compliance activity."[33] Eversource states that the NOPR proposal would "introduce new technical and administrative challenges that will likely impact responsible entities' ability to

[30] NRG Comments at 3.

[31] EEI/NRECA Comments at 12.

[32] *Id.* at 12.

[33] *Id.* at 14-15.

participate in existing voluntary threat information sharing programs."[34] LPPC states that whatever action the Commission takes on Cyber Security Incident reporting, it "must be done with an eye towards causing as little disruption to existing information sharing programs as possible."[35]

25. Trade Associations state that while improving Cyber Security Incident reporting is an appropriate objective, "directing new or revised mandatory reliability standards is not the only tool that NERC and the Commission have for achieving that reliability objective."[36] Trade Associations contend that, in light of the constantly evolving state of cyber security, "the Commission should consider and utilize the most flexible tools to achieve its reliability goals without imposing undue burden on registered entities."[37]

26. APS states that while it "supports the Commission's objectives expressed in the NOPR," it does not agree that modifying the CIP Reliability Standards is the appropriate solution.[38] APS asserts that "the reporting requirements that already exist under Form OE-417 meet the same objectives as the Commission is attempting to satisfy by requiring additional reporting under the CIP Standards as proposed in the NOPR."[39] APS instead

[34] Eversource Comments at 5.

[35] LPPC Comments at 4.

[36] APPA, *et al.* Comments at 3-4.

[37] *Id.* at 4.

[38] APS Comments at 5.

[39] *Id.* at 7.

suggests that "the Commission … direct NERC to modify the CIP Standards to include a requirement for Responsible Entities to submit copies of its Form OE-417 to the E-ISAC and ICS-CERT."[40]

27. EnergySec states that it is "generally in agreement with the Commission's goal of increasing the frequency and detail of incident reporting," but raises concerns with the specifics of the NOPR proposal.[41] EnergySec maintains that "'compromise' as used in the definition of Reportable Cybersecurity Incident does not necessarily imply harm."[42] Therefore, EnergySec argues that "an incident should be considered a 'compromise' if an attacker has obtained the ability to disrupt, even if no disruption occurs."[43] EnergySec states further that it believes "that a clarified understanding of the current definition of Reportable Cybersecurity Incident can sufficiently address the Commission's concerns" since it "can be construed to include certain non-impactful incidents, as well as incidents affecting [ESPs] and [EACMS]."[44]

28. EnergySec also raises a concern that the NOPR proposal is too broad. EnergySec argues that determining incidents that might facilitate future cyber incidents "would be highly subjective and could easily be construed to include systems and networks that are

[40] *Id.* at 5.

[41] EnergySec Comments at 2.

[42] *Id.* at 2.

[43] *Id.* at 2.

[44] *Id.* at 3.

outside the scope of the Commission's authority."[45] EnergySec notes that most failed login or access attempts are benign in nature and "the volume of such events is orders of magnitude larger than what would be an appropriate volume for mandatory reporting."[46] EnergySec states further that while it agrees that successful attacks against ESPs and EACMS should be reported, it does not support including attempted compromise in the reporting requirements since the "[d]etermination of attempted compromise is highly subjective and it would therefore be difficult at best to clearly define within the standards a basis for such determinations."[47]

29. Eversource and Idaho Power do not support the NOPR proposal due to the anticipated increased burden that could result from increased mandatory reporting. Eversource states that "expanding the amount of required information to be reported and increasing the number of recipients of the reports will create undue administrative burdens."[48] In addition, Eversource contends that "the meaning of an attempted compromise is currently undefined and may impose significant burdens on responsible entities to identify such attempts."[49] Idaho Power states that even though "additional reporting can provide some visibility into the types of threats that entities face, additional

[45] *Id.* at 3.

[46] *Id.* at 3.

[47] *Id.* at 3-4.

[48] Eversource Comments at 1.

[49] *Id.* at 6.

administrative burdens such as reporting requirements reduce the finite resources that entities have to monitor and defend their critical infrastructure."[50]

30. LPPC asserts that the NOPR proposal "may yield a substantial quantity of unhelpful information and confusing analysis, while needlessly burdening Registered Entities."[51] LPPC states that it supports NERC's request for flexibility in addressing enhanced Cyber Security Incident reporting and concludes that "a technical conference may productively explore the nature and scope of the various programs that currently exist for information sharing regarding threats and the incremental value of any new requirements."[52] Resilient Societies states that "the modifications proposed to improve the reporting of cybersecurity incidents are unlikely to have any significant positive effect."[53] Specifically, Resilient Societies states that the proposed reporting parameters are not broad enough because "reporting of malware infection is not necessarily within thresholds set on other criteria, such as 'compromise,' 'breach,' 'impact,' or 'disruption.[54]'" Resilient Societies also suggests that the Commission convene a public technical conference.

[50] Idaho Power Comments at 2.

[51] LPPC Comments at 1.

[52] *Id.* at 5-6.

[53] Resilient Societies Comments at 12.

[54] *Id.* at 10.

3. Commission Determination

31. We adopt the NOPR proposal and, pursuant to section 215(d)(5) of the FPA, direct NERC to develop and submit modifications to the Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES. Comments submitted by NERC and others support our determination that enhanced reporting of Cyber Security Incidents will address an existing gap in Cyber Security Incident reporting and will provide useful information on existing and future cyber security risks, as well as provide entities with better visibility into malicious activity prior to an event occurring. As noted in NERC's comments, "[b]roadening the mandatory reporting of Cyber Security Incidents would help enhance awareness of cyber security risks facing entities."[55] Similarly, BPA agrees with the directive to include attempted compromises in an enhanced reporting regime, stating that "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[56] Moreover, while the record reflects differing views on whether broadened

[55] NERC Comments at 4.

[56] BPA Comments at 3.

Cyber Security Incident reporting should be mandatory or voluntary, there is general agreement that improved reporting is an appropriate objective.[57]

32. Some commenters contend that the directive to require mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS is vague and requires clarification. Recognizing this concern, NERC states that "[t]he challenge is to scope any additional mandatory reporting requirements in a manner that collects meaningful data about security risks without creating an unduly burdensome reporting requirement."[58] While we address the threshold for a broadened reporting requirement issue in the next section, as a general matter, we agree with NERC that the scope of any new reporting requirement should be tailored to provide better information on cyber security threats and vulnerabilities without imposing an undue burden on responsible entities. Indeed, the NOPR proposal was not intended to be prescriptive or overly broad, but rather support NERC's efforts to enhance the reporting of Cyber Security Incidents as outlined in NERC's 2017 State of Reliability Report through the standards development process.

33. Some commenters assert that a broadened reporting requirement will overlap, duplicate or otherwise chill voluntary reporting programs, potentially diverting resources away from such programs. Other commenters, however, assert that voluntary reporting

[57] *See* NERC Comments at 4, Trade Associations Comments at 3, APS Comments at 1, BPA Comments at 3, EnergySec Comments at 1, Idaho Power Comments at 2, ITC Comments at 5, IRC Comments at 1, NRG Comments at 2-3.

[58] NERC Comments at 3.

does not adequately address the gap identified in the NOPR because voluntary reporting and mandatory reporting under currently-effective Reliability Standard CIP-008-5 have not resulted in adequate reporting of cybersecurity threats to the BES.[59] As Appelbaum notes, "[w]ithout mandatory reporting scheme a degraded threat image will result."[60]

34. Based on the record, we are not persuaded that our directive to augment current mandatory reporting requirements will adversely impact existing voluntary information sharing efforts. Instead, we agree with NERC's comment that the new "baseline understanding [resulting from broadened mandatory reporting], coupled with the additional context from voluntary reports received by the E-ISAC, [will] allow NERC and the E-ISAC to share that information broadly through the electric industry to better prepare entities to protect their critical infrastructure."[61] Moreover, we do not anticipate that the incremental burden of the directed modifications will divert significant resources from other information sharing programs since responsible entities are already required to monitor and log successful login attempts, detected failed access attempts, and failed login attempts under Reliability Standard CIP-007-6, Requirement R4.1. Nor do we anticipate that the incremental burden of complying with the directed Reliability Standards modifications would be significantly more than the burden of responding to a standing data or information request under Section 1600. We also do not believe that broadened mandatory reporting is at cross-purposes with voluntary cybersecurity-related

[59] *See id.* at 4-5.

[60] Appelbaum Comments at 7.

[61] NERC Comments at 4.

programs offered by DHS and other government agencies. We believe that voluntary programs that focus on cyber response and sharing of cyber threat information across industry are important initiatives that should be supported. However, the comments do not provide a compelling explanation why the broadening of mandatory reporting will supplant or inhibit voluntary programs.

35. While we agree with EnergySec that revisions to the current definition of Reportable Cyber Security Incident could address some aspects of our directive, a modified definition alone would not address the need to specify the required information in Cyber Security Incident reports to improve the quality of reporting and allow for ease of comparison, or establish deadlines for submitting a report to facilitate timely information sharing. Therefore, while we believe that a modified definition of Reportable Cyber Security Incident could address part of the Commission's concerns, additional modifications would be necessary to meet the full scope of our directive.

36. In addition, we do not agree with Resilient Societies that the detection of malware infecting a responsible entity's ESP or associated EACMS would fall outside the new reporting requirement. While Resilient Societies asserts that a malware infection would not meet the threshold of a compromise, breach, impact, or disruption, we believe that it would fall within the parameters of an attempted compromise. As discussed in the next section, however, we believe that it is appropriate for NERC to address the reporting threshold through the standards development process in order to weigh the diverse technical opinions on how to identify the appropriate assets and the level of attempted compromise that warrants reporting. Accordingly, we are not persuaded to convene a

technical conference. Rather, persons interested in the development of appropriate detailed parameters of the augmented reporting requirements should participate in the NERC standards development process.

37. In sum, we conclude that the record supports our determination that directing NERC to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP, as well as associated EACMS, is appropriate to carry out FPA section 215. Therefore, pursuant to FPA section 215(d)(5), we direct NERC to develop and submit modifications to the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. As noted above, we direct NERC to submit the directed modifications within six-months of the effective date of this Final Rule.

B. Threshold for a Reportable Cyber Security Incident

1. NOPR

38. The NOPR proposed to direct NERC to modify the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. The NOPR explained that reporting attempts to compromise, instead of only successful compromises, is consistent with current monitoring requirements in Reliability Standard CIP-007-6, Requirement R4.1, which mandates logging of detected successful login attempts,

detected failed access attempts and failed login attempts.[62] In addition, the NOPR identified other reporting regimes that include attempts within the general definition of a "cyber incident." Specifically, DHS defines a "cyber incident" as "attempts (either failed or successful) to gain unauthorized access to a system or its data…."[63] The E-ISAC defines a "cyber incident" as including unauthorized access through the electronic perimeter as well as "a detected effort … without obvious success."[64] And ICS-CERT defines a "cyber incident" as an "occurrence that actually or potentially results in adverse consequences…."[65]

39. As noted above, an ESP is defined in the NERC Glossary as the "logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." The purpose of an ESP is to manage electronic access to BES Cyber Systems to support the protection of the BES Cyber Systems against compromise that could lead to misoperation or instability in the BES. The NOPR explained that since an ESP is intended to protect BES Cyber Systems, it is reasonable to establish the compromise of, or attempt to compromise, an ESP as the minimum reporting threshold.

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[62] *See* Reliability Standard CIP-007-6 (Cyber Security – Systems Security Management), Requirement R4.1.

[63] *See* United States Computer Emergency Readiness Team (US-CERT) Incident Definition: https://www.us-cert.gov/government-users/compliance-and-reporting/incident-definition.

[64] *See* E-ISAC Incident Reporting Fact Sheet document: http://www.nerc.com/files/Incident-Reporting.pdf.

[65] *See* ICS-CERT Published "Common Cyber Security Language" document: https://ics-cert.us-cert.gov/sites/default/files/documents/Common%20Cyber%20Language_S508C.pdf.

40. In addition, the NOPR identified an ESP's associated EACMS as another threshold for a Reportable Cyber Security Incident. As explained in the NOPR, EACMS are defined in the NERC Glossary as "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems." More specifically, EACMS include, for example, firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems.

41. While the Commission proposed to include EACMS within the scope of the proposed directive, the Commission also sought comment on the possibility of excluding EACMS from the scope of the proposed directive.

2. Comments

42. NERC supports the NOPR proposal to limit the scope of Cyber Security Incident reporting to incidents that compromise or attempt to compromise a responsible entity's ESP or associated EACMS. NERC explains that any new reporting requirements "need to be scoped in a manner that provides for meaningful reporting of cyber security risks but does not unduly burden entities."[66] Specifically, NERC states:

> Because the ESP protects some of the most important Cyber Assets and the EACMS control or monitor access to those Cyber Assets, NERC agrees that reporting on attempts to compromise these security measures would provide valuable data while also imposing a reasonable burden on entities given the limited traffic they should experience.[67]

[66] NERC Comments at 6.

[67] *Id.* at 7.

NERC notes that some EACMS devices "may provide important early indicators of future compromise" and, therefore, NERC states that it "supports including EACMS in the reporting threshold in addition to the ESP and notes that logging attempts to compromise the ESP and some EACMS devices does not impose an unreasonable burden on entities."[68]

43. While NERC supports adopting the compromise or attempt to compromise a responsible entity's ESP or an EACMS associated with an ESP as a threshold for Cyber Security Incident reporting, NERC explains that "there is still a need to refine the scope of the proposed directive to ensure that it would provide meaningful data without overburdening entities."[69] Specifically, NERC states that there is a need to "outline the parameters of an 'attempt to compromise' in order to issue a precise data request."[70] In particular, NERC states that it "would consider the common understanding of adverse activities that are early indicators of compromise, such as campaigns against industrial control systems, to help refine the parameters."[71] In addition, NERC notes that EACMS, as defined in the NERC Glossary, include a wide variety of devices that perform control and monitoring functions. NERC states further that it "needs to consider whether to define the reporting threshold to differentiate between the various types of EACMS for

[68] *Id.* at 8.

[69] *Id.* at 9.

[70] *Id.* at 9.

[71] *Id.* at 9.

reporting purposes."[72] Therefore, NERC requests that the Commission provide flexibility in refining the threshold for Cyber Security Incident reporting.

44. Trade Associations, APS, BPA, EnergySec, Resilient Societies, IRC, ITC, and NYPSC generally support the reporting threshold proposed in the NOPR, but caution that any new or modified requirements should be properly scoped. Trade Associations state that the NOPR proposal "is potentially overbroad and could result in unduly burdensome reporting requirements that *reduce* awareness of significant cyber threats."[73] Trade Associations also contend that a new or revised Reliability Standard "should not include the proposed generic threshold of reporting *any* incidents that compromise or attempt to compromise an ESP or EACMS."[74] Instead, Trade Associations recommend that the Commission "give NERC sufficient flexibility to define appropriate reporting thresholds for attempted compromises of an ESP or EACMS."[75]

45. APS asserts that, given the differences among EACMS, it does not support the inclusion of all EACMS or the exclusion of all EACMS from an enhanced reporting requirement. APS states that while it "concurs that the incidents impacting the ESP should certainly be in scope of reporting, it is concerned that the exclusion of EACMS (which includes [Electronic Access Points (EAP)]) results in a likely compromise

[72] *Id.* at 9.

[73] APPA, *et al*. Comments at 5 (emphasis in original).

[74] *Id.* (emphasis in original).

[75] *Id.* at 5.

scenario going unreported."[76] Specifically, APS notes that "a user's credentials to an Intermediate System, which includes/can be classified as an EAP(s) and/or EACMS, could be compromised."[77] APS contends that such a compromise would not implicate the ESP, but could impact or attempt to impact a BES Cyber Asset or System. APS states, however, that "there are numerous EACMS for which a compromise scenario would not be critical or allow potential access to an ESP."[78] Therefore, APS maintains that an evaluation of the functions of various EACMS is needed before they can be included in any reporting requirement.

46. BPA states that a broader definition of a Reportable Cyber Security Incident is necessary since the current definition only addresses actual compromises. BPA avers that "information about certain attempts to compromise will likely better assist the industry in preventing successful cyber attacks."[79] BPA states that the current definition of a Cyber Security Incident is a good starting point for a revision since it includes attempts to compromise or disrupt. BPA cautions, however, that the current definition of Cyber Security Incident "may be too broad and result in overreporting of information."[80]

[76] APS Comments at 9.

[77] *Id.*

[78] *Id.*

[79] BPA Comments at 3.

[80] *Id.* at 3.

47. EnergySec states that it "generally agree[s] that successful attacks against ESPs and EACMS should be within the scope of reporting; [but] disagree[s] with the proposal to include attempted compromise in the reporting requirements."[81] In addition, EnergySec suggests that monitoring-only systems be excluded from any reporting requirement, stating that "[a]lthough compromise of monitoring systems could assist an attack, such a compromise would not directly permit access."[82] Resilient Societies states that "[e]xcluding [EACMS] from the Commission directive could exempt reporting of attempted compromises."[83] IRC states that "adding EACMS to the requirement for mandatory reporting would be beneficial, not only because of their role as a boundary point, but also because EACMS perform other roles that support the BES Cyber Systems."[84] IRC cautions, however, that "[w]ithout providing further definitions or criteria, the NOPR's proposal to require reporting of all 'attempts to compromise' the ESP or EACMS is unclear and potentially unachievable."[85]

48. While ITC generally supports the NOPR proposal, ITC "requests that the Commission refrain from including unsuccessful attempts to compromise an ESP-

[81] EnergySec Comments at 3-4.

[82] *Id.* at 4.

[83] Resilient Societies Comments at 14.

[84] IRC Comments at 5.

[85] *Id.* at 3-4.

associated EACMS in the revised definition of a Cyber Security Incident."[86] ITC notes that responsible entity systems with publicly-visible IP addresses "sustain a regular stream of denial of service attempts, phishing emails, attempted firewall breaches, untargeted and targeted malware, and other common cybersecurity threats for which countermeasures are well-established and which pose a miniscule chance of success."[87] ITC states that including "attempted compromises of ESP-associated EACMS would appear to require reporting for a sizeable number of these common events."[88] Therefore, ITC states that while it "supports expanding the definition of Reportable Cyber Incidents to include incidents that compromise, or attempt to compromise, a responsible entity's ESP, ITC would urge the Commission to direct NERC to include only actual breaches of a responsible entity's ESP-associated EACMS, and not attempted-but-unsuccessful compromises."[89] NYPSC notes that "[f]ailed cyber attacks occur on a continuous basis, all the time…" and, therefore, "[a] reporting requirement of every attempted security attack may be overly burdensome for reporting entities."[90] NYPSC "suggests FERC

[86] ITC Comments at 5.

[87] *Id.* at 5.

[88] *Id.* at 5.

[89] *Id.* at 5.

[90] NYPSC Comments at 5-6.

consider developing clear criteria of the required reporting based on its review of the comments and recommendations from reporting entities."[91]

49. Idaho Power states that "additional reporting requirements do not increase cyber security."[92] Idaho Power contends that "additional administrative burdens such as reporting requirements reduce the finite resources that entities have to monitor and defend their critical infrastructure."[93] In addition, Idaho Power states that EACMS "should be excluded from any additional requirements and only BES Cyber Systems and associated devices should be included in any further reporting requirements."[94]

50. Other commenters support expanding the enhanced reporting requirement beyond what was proposed in the NOPR. NRG supports the NOPR proposal to direct NERC to develop modifications to the CIP Reliability Standards to improve the reporting of Cyber Security Incidents. NRG also supports including EACMS as a threshold for reporting. In addition, NRG "recommends that the scope of the NOPR avoid limiting the requirement to High and Medium Impact BES Cyber Systems."[95] Specifically, NRG notes that the NOPR proposal "would limit the requirement to High and Medium Impact BES Cyber Systems as ESPs and EACMS are not required establishments at Low Impact BES Cyber

[91] *Id.* at 6.

[92] Idaho Power Comments at 2.

[93] *Id.*

[94] *Id.*

[95] NRG Comments at 5.

Systems."[96] Therefore, NRG states that "any modification to the referenced CIP Reliability Standards should be applicable to all BES Cyber Systems with External Routable Communications."[97]

51. Appelbaum supports the NOPR proposal to include the attempted or actual compromise of an ESP or EACMS in the mandatory reporting requirement. However, Appelbaum "propose[s] the Commission consider adding Physical Security Perimeters and Physical Access Control Systems (PACS) as well."[98] Simon supports the NOPR proposal, but encourages the Commission to broaden the directive to include low impact BES Cyber Systems. Specifically, Simon states that "[o]mission of mandatory reporting for the disruption, or an attempt to disrupt, the operation of electronic access controls for BES assets with low impact BES Cyber Systems leaves a large blind spot in the Commission's effort to learn of efforts to harm the reliable operation of the bulk electric system."[99] Isologic does not support limiting Cyber Security Incident reporting to situations involving an entity's ESP or associated EACMS. Isologic states that "there are few CIP standards for 'secure perimeters' and for the mass of BES Low Impact Facilities, (substations), security is at the fence line, not in ESPs."[100]

[96] *Id.* at 2.

[97] *Id.*

[98] Appelbaum Comments at 7.

[99] Simon Comments at 4.

[100] Isologic Comments at 7.

3. Commission Determination

52. The record in this proceeding supports establishing the compromise or attempted compromise of an ESP as the appropriate threshold for a Reportable Cyber Security incident. In addition, with exceptions, the comments support including EACMS associated with an ESP as part of the reporting threshold. As NERC notes, an "ESP protects some of the most important Cyber Assets and the EACMS control or monitor access to those Cyber Assets."[101] While we believe that ESPs and EACMS should be within the scope of a broadened reporting requirement, the comments, correctly in our view, point to the need to establish an appropriate scope for reporting. As NERC states, "there is still a need to refine the scope of the proposed directive to ensure that it would provide meaningful data without overburdening entities."[102] This concern is reflected in a number of comments, pointing to the need to identify the appropriate assets to monitor (for example, only EACMS associated with an ESP) and to clearly define an "attempt to compromise."[103]

53. The comments generally support the view that NERC should have the flexibility to establish an appropriate reporting threshold. We recognize the need for a certain level of flexibility and believe that it is appropriate for NERC to address the specific reporting threshold through the standards development process. However, as discussed further

[101] NERC Comments at 7.

[102] *Id.* at 9.

[103] *See* NERC Comments at 9, APPA, *et al*. Comments at 5, APS Comments at 9, BPA Comments at 3, EnergySec Comments at 3, IRC Comments at 3-4, ITC Comments at 5, NYPSC Comments at 6.

below, we provide guidance on certain aspects of how NERC should identify EACMS for reporting purposes and what types of attempted compromise must be reported.

54. With regard to identifying EACMS for reporting purposes, NERC's reporting threshold should encompass the functions that various electronic access control and monitoring technologies provide. Those functions must include, at a minimum: (1) authentication; (2) monitoring and logging; (3) access control; (4) interactive remote access; and (5) alerting.[104] Reporting a malicious act or suspicious event that has compromised, or attempted to compromise, a responsible entity's EACMS that perform any of these five functions would meet the intended scope of the directive by improving awareness of existing and future cyber security threats and potential vulnerabilities. Since responsible entities are already required to monitor and log system activity under Reliability Standard CIP-007-6, the incremental burden of reporting of the compromise or attempted compromise of an EACMS that performs the identified functions should be limited, especially when compared to the benefit of the enhanced situational awareness that such reporting will provide.

55. With regard to the definition of "attempted compromise" for reporting purposes, we consider attempted compromise to include an unauthorized access attempt or other

[104] *See* NERC Glossary of Terms definition of EACMS. *See also* Reliability Standard CIP-006-6, Requirement R1.5 (Physical Security Plan) at 10 ("[i]ssue an alarm or alert in response to detected unauthorized access" to certain High and Medium Impact BES Cyber Systems and associated EACMS); Reliability Standard CIP-007-6, Requirement R4.2 (Security Event Monitoring) at 16; and Reliability Standard CIP-007-6, Requirement R5.7 (System Access Control) at 25.

confirmed suspicious activity. ITC raises a concern that including unsuccessful attempts to compromise an EACMS associated with an ESP would require reporting a significant number of events. We note, however, that limiting the reporting threshold to only EACMS that are associated with an ESP should limit the reporting burden since these assets should be located apart from the responsible entity's broader business IT networks. Moreover, as discussed in the next section, we also believe that a flexible reporting timeline that reflects the severity of a Cyber Security Incident could also help address the potential burden of reporting attempted compromises.

56. With regard to BPA's suggestion that a revised definition of Reportable Cyber Security Incident is necessary, as discussed above, revisions to the current definition of Reportable Cyber Security Incident could address certain aspects of the NOPR proposal, although a modified definition alone would not address the need to specify the required information in cyber security incident reports to improve the quality of reporting and allow for ease of comparison, or establish deadlines for submitting a report to facilitate timely information sharing. Therefore, although we believe that a modified definition of Reportable Cyber Security Incident could address part of the Commission's concerns, additional modifications to the Reliability Standards would be necessary to meet the security objective of the directives discussed herein.

57. A number of commenters request that we expand the directive to include a broader scope of assets, including low impact BES Cyber Systems. However, we decline to expand the scope of Cyber Security Incident reporting beyond the ESP and associated EACMS at this time. The focus on ESPs and associated EACMS is intended to provide

threat information on BES Cyber Systems that have the greatest impact on BES reliability while imposing a reasonable reporting burden on responsible entities. Nevertheless, the Commission could revisit this issue if there is demonstrated need for expanded Cyber Security Incident reporting.

58. Therefore, we adopt the NOPR proposal and conclude that the compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS is a reasonable threshold for augmented Cyber Security Incident reporting.

C. Appropriate Procedural Approach to Augment Cyber Security Incident Reporting

1. NOPR

59. The NOPR proposed to direct NERC to modify the CIP Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, while also seeking comment on whether a request for data or information pursuant to Section 1600 of the NERC Rules of Procedure would effectively address the reporting gap.

2. Comments

60. While NERC supports broadened mandatory Cyber Security Incident reporting, NERC does not support the NOPR proposal to direct a modification to the Reliability Standards. Instead, NERC requests flexibility to determine the appropriate reporting procedure. Specifically, NERC proposes to "use the [Rules of Procedure] Section 1600 process for gathering data used for system performance."[105] NERC maintains that it has

[105] NERC Comments at 10.

"successfully shifted to using Section 1600 for other data collection efforts, such as the collection of reports on Protection System Misoperation."[106] NERC explains further that the Section 1600 process would be used to "supplement the existing voluntary reporting of cyber security threats to E-ISAC."[107]

61. NERC states that the Section 1600 process "provides many of the same benefits as Reliability Standards," such as stakeholder and Commission staff input.[108] NERC also states that, similar to Reliability Standards, compliance with Section 1600 is mandatory. NERC explains that if a responsible entity does not respond to a Section 1600 data request, "NERC has the authority under the [Rules of Procedure] to take such action as NERC deems appropriate to address a situation where a Rule of Procedure cannot practically be complied with or has been violated."[109] NERC explains that the Section 1600 data request process provides the flexibility to revise or update the data request, if necessary, as well as "the flexibility to determine the appropriate timeline for submitting the data."[110] NERC states that while it may continue to use the Reliability Standards for data collection for evidence of compliance or to facilitate sharing of information between entities for BES operations, it "has found the [Rules of Procedure] Section 1600 process

[106] *Id.*

[107] *Id.*

[108] *Id.*

[109] *Id.* at 11.

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

to be effective for data collection to assess system performance."[111] NERC cites a standing Section 1600 data request for entities to submit quarterly data on Protection System Misoperations as an example.

62. LPPC supports the use of the Section 1600 process to facilitate enhanced Cyber Security Incident reporting. LPPC states that it "supports a more flexible approach to collection of actionable information through the data request process outlined in NERC ROP Section 1600."[112] LPPC asserts that the data request approach offers flexibility that the standards development process does not. Specifically, LPPC states that "compliance with a NERC data request is mandatory for applicable entities, while the data request procedures specified under [Rules of Procedure] Section 1600 also provide a more efficient process to update or revise a data request as needed to respond to rapidly-changing security threats."[113] Finally, LPPC opines that "it seems appropriate to remove the data collection process from the enforcement process associated with mandatory Reliability Standards."[114]

63. APS, BPA, Resilient Societies, IRC, and NRG oppose the use of the Section 1600 process to facilitate enhanced Cyber Security Incident reporting. APS asserts that a request for data pursuant to Section 1600 would not effectively address the reporting gap

[111] *Id.* at 12.

[112] LPPC Comments at 6-7.

[113] *Id.* at 7.

[114] *Id.*

and current lack of awareness of cyber-related incidents. Specifically, APS argues that a data request would create an independent, redundant reporting obligation to NERC or a regional entity and would subject the provisions of reported information to the confidentiality and data sharing processes set forth in Rules of Procedure Section 1500, unnecessarily delaying sharing and distribution of information.[115] APS states further that the Section 1600 process "adds significant additional administrative burden for all involved entities, which is inefficient and unnecessary and presents a potential obstacle to the very sharing and distribution that is a critical part of the Commission's objectives set forth in the NOPR."[116]

64. BPA comments that a data request is not an effective means of obtaining information about cyber security incidents. BPA explains that Section 1600 data requests "are one time requests for existing data, and […] not the appropriate vehicle for ensuring ongoing reporting necessary to make data about Cyber Security Incidents effective."[117] Resilient Societies states that "[e]xamination of NERC Rules of Procedure Section 1600 shows the intent of [the] rule is to facilitate one-time requests for data."[118] Therefore, Resilient Societies asserts that the Section 1600 reporting procedures "would be a poor fit for a standing order for data on cybersecurity incidents that occur continually."[119] NRG

[115] APS Comments at 16.

[116] *Id.* at 16-17.

[117] BPA Comments at 4.

[118] Resilient Societies Comments at 15.

[119] *Id.*

opposes the use of the Section 1600 data request process asserting that a request for data or information would neither address the current lack of awareness of cyber-related incidents, nor satisfy the goals of the proposed directive.

65. APS, as discussed above, suggests adopting the DOE Electric Disturbance Events, Form OE-417 as the primary reporting tool for Cyber Security Events. EnergySec, for its part, suggests that the Commission could direct NERC to require entities to develop and implement an information sharing plan.[120] According to EnergySec, such an approach should provide broad discretion to entities and ensure that compliance oversight efforts cannot result in second-guessing of decisions regarding which information to share, when, or with whom. IRC suggests, alternatively, that the Commission allow entities to comply with the reporting requirements by participating in the Cyber Risk Information Sharing program. IRC explains that the program allows entities to automatically report information to E-ISAC for analysis against classified information. IRC states that responsible entities that "automatically report indicators of compromise through these systems will share information at machine speed, and this should be considered superior to manual reporting, which requires much slower decision-making."[121]

3. Commission Determination

66. As discussed above, we adopt the NOPR proposal and direct NERC to develop modifications to the NERC Reliability Standards to improve mandatory reporting of

[120] EnergySec Comments at 6.

[121] IRC Comments at 7.

Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES. We have considered the arguments raised in the comments for using Reliability Standards, Section 1600 information and data requests, and other vehicles to implement augmented Cyber Security Incident reporting. On balance, we conclude that broadened mandatory reporting pursuant to Reliability Standard requirements is more aligned with the seriousness and magnitude of the current threat environment and the more effective approach to improve awareness of existing and future cyber security threats and potential vulnerabilities.

67. First, the development of a Reliability Standard provides the Commission with an opportunity to review and ultimately approve a new or modified Reliability Standard, ensuring that the desired goals of the directive are met. Moreover, the Reliability Standards development process allows for the collaboration of industry experts in developing a draft standard and also gives interested entities broader opportunity to participate and comment on any proposal that is developed. In contrast, NERC's process for developing a Section 1600 data request provides for less stakeholder input and only informal review of a draft data request by Commission staff. Thus, in this circumstance, the standards development process is preferable for the development of augmented cyber incident reporting requirements that satisfy the scope of the Commission's directive.

68. Second, the development of a Reliability Standard provides better assurance of accurate, complete, and verifiable reporting of cyber security incidents. The Commission has well-defined authority and processes under section 215(e) of the FPA to audit and enforce compliance with a Reliability Standard. While NERC notes that a responsible

entity must respond to a NERC Section 1600 data request, NERC cannot impose sanctions on registered entities who fail to respond to such data requests. Rather, a failure to comply would be a violation of the Commission's regulations,[122] requiring a referral to the Commission for action. Such a process would be a departure from the clearly defined processes used to enforce compliance with the Reliability Standards. Moreover, it is unclear how NERC would even learn of such a failure since, unlike mandatory Reliability Standards, compliance with Section 1600 data requests are not subject to regular audit. Accordingly, given the importance of accurate, complete, and verifiable cyber security incident reporting, we find that the more robust and well-established compliance and enforcement processes associated with mandatory Reliability Standards are desirable in this instance.

69. Third, we are not persuaded by NERC's assertion that a Section 1600 data request is preferable in this instance because it allows for flexibility and faster modification should a need arise for future revisions to the collection of cyber incident reporting data. We do not anticipate that there would be a need to change the parameters of the event report, given that the anticipated reporting requirements should not be technology-specific, but rather, broad enough to capture basic data even as the nature of cyber security incidents evolve. Specifically, the NOPR proposed that the minimum set of

[122] 18 CFR 39.2(b) (2017) ("All entities subject to the Commission's reliability jurisdiction…shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization and Regional Entity Rules made effective under this part.")

attributes to be reported should include: (1) the functional impact, where possible to determine, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident. Since these attributes are general in nature and not technology specific, they would not need to be refined as the underlying cyber threats evolve, nor would they need to be refined quickly.

70. In a similar vein, the assets (i.e., EACMS) subject to the enhanced reporting requirements should be identified based on function, as opposed to a specific technology that could require a modification in the reporting requirements should the underlying technology change. As discussed above, those functions must include, at a minimum: (1) authentication; (2) monitoring and logging; (3) access control; (4) interactive remote access; and (5) alerting. Finally, since the level of attempted compromise that warrants reporting should reflect unauthorized access attempts and other confirmed suspicious activity, we do not anticipate that a modification would be required in the future. Nevertheless, should the situation demand a more timely change in data collection or should NERC desire to collect additional information that is outside the scope of the proposed Reliability Standard, NERC could use the Section 1600 data request process to supplement information reported under a mandatory Reliability Standard.

71. Finally, requiring a data collection in a Reliability Standard is consistent with existing practices since responsible entities are currently required to maintain the types of

information that would lead to a reportable Cyber Security Incident pursuant to Reliability Standard CIP-007-6, Requirement R4.1.

72. While we recognize that NERC could likely develop a Section 1600 data request more quickly than a mandatory Reliability Standard, given the potential complexity of considering reporting requirements for the various EACMS, we believe that the technical depth of a standard development process is more appropriate for this case. Although NERC states that it has successfully used ROP Section 1600 to collect data on system performance, in this circumstance the information being reported relates to threats and potential compromises that may require immediate or near-term action as opposed to retrospective reporting on Misoperations, as Section 1600 has been used.

73. We also do not support adopting the DOE Form OE-417 as the primary reporting tool for reporting Cyber Security Incidents, as suggested by some commenters. The reporting criteria in our directive are distinguishable and more aligned with a risk management approach than the information requested in the DOE Form OE-417. Specifically, the DOE Form OE-417 has twelve generic criteria for filing a report to the DOE, of which only two reflect the criteria outlined in the NOPR proposal, which are discussed in the following section. The DOE Form OE-417 does not address factors such as attack vector, functional impact and level of intrusion. In addition, the definition of a "Cyber Event" in the DOE Form OE-417 filing instructions does not align with the definition of Cyber Security Incident in the NERC Glossary of Terms, let alone a

Reportable Cyber Security Incident.[123] Nor does the DOE Form OE-417 require reporting to E-ISAC or ICS-CERT as our directive requires.

74. In sum, we conclude that modifications to the NERC Reliability Standards to improve mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES, is the appropriate approach to improve Cyber Security Incident reporting.

D. Content and Timing of a Cyber Security Incident Report

1. NOPR

75. The NOPR proposed to direct that NERC modify the CIP Reliability Standards to specify the required content in a Cyber Security Incident report. Specifically, the NOPR proposed that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempt to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident. The NOPR noted that the proposed attributes are the same as attributes already used by DHS for its multi-sector reporting and summarized by DHS in an annual report. The NOPR stated that specifying the required content should improve the quality of reporting by ensuring that basic information is provided; and

[123] *See* Department of Energy Electric Emergency Incident and Disturbance Report – Form OE 417. Form OE-417 defines a Cyber Event as a disruption on the electrical system and/or communication system(s) caused by unauthorized access to computer software and communications systems or networks including hardware, software, and data. https://www.oe.netl.doe.gov/oe417.aspx

allowing for ease of comparison across reports by ensuring that each report includes specified fields of information. The NOPR sought comment on the proposed attributes and, more generally, the appropriate content for Cyber Security Incident reporting to improve awareness of existing and future cyber security threats and potential vulnerabilities.

76. In addition, the NOPR proposed to direct NERC to establish requirements outlining deadlines for filing a report once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity. The NOPR stated that the reporting timeline should reflect the actual or potential threat to reliability, with more serious incidents reported in a more timely fashion. The NOPR explained that a reporting timeline that takes into consideration the severity of a Cyber Security Incident should minimize potential burdens on responsible entities.

77. The NOPR also proposed that the reports submitted under the enhanced mandatory reporting requirements would be provided to E-ISAC, similar to the current reporting scheme under Reliability Standard CIP-008-5, as well as ICS-CERT or any successor organization. While the NOPR stated that the detailed incident report would not be submitted to the Commission, the NOPR proposed to direct NERC to file publicly an annual report reflecting the Cyber Security Incidents reported to NERC during the previous year. Specifically, the NOPR proposed to direct NERC to file annually an

anonymized report providing an aggregated summary of the reported information, similar to the ICS-CERT annual report.[124]

2. Comments

78. NERC supports the minimum set of reporting attributes proposed in the NOPR, stating that "this level of detail regarding each reported Cyber Security Incident will not only help NERC understand the specific threat but also help NERC understand trends in threats over time."[125] NERC also does not oppose either filing an annual, anonymized summary of the reports with the Commission, or submitting the reports of U.S.-based entities to the ICS-CERT in addition to E-ISAC. Finally, while NERC supports the concept of imposing a deadline for entities to submit full reports of Cyber Security Incidents, NERC requests flexibility to determine the appropriate timeframe. Specifically, NERC states that it "will determine an appropriate deadline for reports so that NERC can use the data for awareness and early indicators of potential compromise but also consider whether reporting for historical analysis can provide insight to the trends and effectiveness of industry's security controls."[126]

79. ITC, IRC, and NRG support the minimum set of reporting attributes proposed in the NOPR. ITC states that the NOPR proposal reflects "a reasonable set of baseline

[124] NOPR, 161 FERC ¶ 61,291 at 42.

[125] NERC Comments at 14.

[126] *Id.*

requirements for reporting."[127] While ITC raises a concern that the collective information in a report could potentially lead to the identification of the reporting entity, ITC states that it "will work within the NERC stakeholder and standards development process to ensure that the Standards submitted in response to the Commission's final rule are structured to preserve anonymity to the maximum extent practicable."[128] IRC asserts that "it will be beneficial for responsible entities to report indicators of compromise that are detected in potential cyberattacks against their systems in standard form."[129] NRG recommends that mandatory reporting include: "content Date, Time, Duration of Incident, Origination of the attack, threat vector, targeted system (or OS), vulnerability exploited, [and] method used to stop/prevent the attack."[130]

80. Appelbaum, APS, EnergySec, Resilient Societies, and Idaho Power raise concerns with the minimum set of reporting attributes proposed in the NOPR. According to Appelbaum, a count by category of asset, attack vector, and impact is sufficient for the mandatory reporting. APS contends that "because each entity's network topology, architecture, applications, and other characteristics are different, any requirement to

[127] ITC Comments at 6.

[128] *Id.*

[129] IRC Comments at 7.

[130] NRG Comments at 5.

provide the functional impact and level of intrusion as part of reporting is of very low value and should not be included as mandatory attributes of reporting."[131]

81. APS, however, "agrees that information regarding attack vectors could be more relevant, actionable information to be shared."[132] EnergySec expresses concern that including the proposed set of reporting attributes as a requirement could be construed to require significant forensic and analysis efforts. Resilient Societies suggests that the Commission leverage prior work done by the federal government as opposed to establishing new report content. Specifically, Resilient Societies suggests that the Commission adopt the US-CERT "Federal Incident Notification Guidelines." Idaho Power states that a "description of the event and the system(s) affected along with a fact pattern describing the situation and known information at the time the report is submitted should be sufficient."[133]

82. With regard to the timing of reports, ITC questions whether an initial report of a Cyber Security Incident would have to be submitted to ICS-CERT as well as E-ISAC. ITC opines that "the existing one-hour reporting requirement poses a significant compliance challenge, and that requiring that the initial report also be provided to ICS-CERT would be unworkable under that timeframe."[134] IRC states that "[t]he timeframe

[131] APS Comments at 11-12.

[132] *Id.* at 12.

[133] Idaho Power Comments at 3.

[134] ITC Comments at 7.

for completing a full report depends on the scale and scope of the investigation [and] FERC should consider requiring that reports be updated at a certain frequency until the full report is complete."[135] IRC recommends a 90-day update requirement until a report is finalized. NRG recommends that Cyber Security Incident reports should be submitted after existing industry processes have been followed relating to Incident Reporting and Response Plans. In addition, NRG recommends that the Commission consider directing NERC to file a quarterly report in addition to the annual report.

83. APS recommends aligning the timing of any mandatory reporting obligations with the timing dictated in Form OE-417. APS contends that reporting events that "could, but didn't, cause harm to the BES and/or facilitate subsequent efforts to harm … should be far enough removed from the incident to not divert resources from incident response and to ensure that enough details are known about the incident to provide an accurate, thorough report.[136]

84. EnergySec agrees that clear timelines should be included in any new mandatory Cyber Security Incident requirements. EnergySec further comments that the timelines should factor in the severity of the incident and the level of effort required to complete an investigation. Resilient Societies offers that "[i]n an ideal world, reporting of cybersecurity incidents would take place at machine speed" and suggests that the

[135] IRC Comments at 8.

[136] APS Comments at 13.

Commission "allow and preferably require automated reporting, at least for an initial report."[137] Idaho Power states that, should the Commission require timelines for reporting, it should ensure that an entity has adequate time to analyze each event before the reporting deadline.

85. Lasky supports entities being required to report Cyber Security Incidents to both E-ISAC and ICS-CERT, and states that "it would be prudent to report all incidents to the United States Cyber Emergency Response Team (US-CERT)" as well.[138]

3. Commission Determination

86. As discussed below, we adopt the NOPR proposal on minimum reporting attributes and timing, in response to the commenters' concerns, but we also leave discretion to NERC to develop the reporting timelines in the standards development process by considering several factors so that the timelines provide for notice based upon the severity of the event and the risk to BES reliability, with updates to follow initial reports.

87. The comments generally support the proposed minimum set of reporting attributes. For example, NERC supports the proposed content for a Cyber Security Incident report, while requesting flexibility to determine the appropriate reporting timeframe. As noted by ITC, the NOPR proposal reflects "a reasonable set of baseline

[137] Resilient Societies Comments at 15.

[138] Lasky Comments at 1.

requirements for reporting."[139] Certain comments do raise concerns with the proposed reporting attributes, especially in the case of attempts versus actual compromises.

88. In our view, a new or revised Cyber Security Incident report should include, at a minimum, the information outlined in the NOPR proposal, where available. Specifically, the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident. In addition, we agree that any reporting requirement should not take away from efforts to mitigate a potential compromise.

89. With regard to timing, we conclude that NERC should establish reporting timelines for when the responsible entity must submit Cyber Security Incident reports to the E-ISAC and ICS-CERT based on a risk impact assessment and incident prioritization approach to incident reporting.[140] This approach would establish reporting timelines that are commensurate with the adverse impact to the BES that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Higher risk incidents, such as detecting malware within the ESP and associated EACMS or an

[139] ITC Comments at 6.

[140] Similar to the Cyber Incident Severity Schema in DHS's National Cyber Incident Response Plan, Annex D (Reporting Incidents to the Federal Government) at 41 (2016), https://www.us-cert.gov/sites/default/files/ncirp/National_Cyber_Incident_Response_Plan.pdf.

incident that disrupted one or more reliability tasks, could trigger the report to be submitted to the E-ISAC and ICS-CERT within a more urgent timeframe, such as within one hour, similar to the current reporting deadline in Reliability Standard CIP-008-5.[141] For lower risk incidents, such as the detection of attempts at unauthorized access to the responsible entity's ESP or associated EACMS, an initial reporting timeframe between eight and twenty-four hours would provide an early indication of potential cyber attacks.[142] For situations where a responsible entity identifies other suspicious activity associated with an ESP or associated EACMS, a monthly report could, as NERC states, assist in the analysis of trends in activity over time.[143]

90. With regard to the appropriate recipients for Cyber Security Incident reports, we determine that the reports should be provided to E-ISAC, similar to the current reporting

[141] An example of incident categories is the Chairman of the Joint Chiefs of Staff Manual, Cyber Incident Handling Program, Enclosure B, Appendix A to Enclosure B (Cyber Incident and Reportable Cyber Event Categorization) (2012), http://www.jcs.mil/Portals/36/Documents/Library/Manuals/m651001.pdf?ver=2016-02-05-175710-897.

[142] *See* Department of Energy Electric Emergency Incident and Disturbance Report, Form OE-417 (six-hour reporting deadline for cyber events that could potentially impact electric power system reliability) found at: https://www.oe.netl.doe.gov/docs/OE417_Form_05312021.pdf; Nuclear Regulatory Commission Regulatory Guide 5.71 (four-hour reporting deadline for cyber events that could have caused an adverse impact) found at: https://www.nrc.gov/docs/ML0903/ML090340159.pdf; *see also* Reliability Standard EOP-004-3 (Event Reporting), Requirement R2 (requiring a report within twenty-four hours for an events that impact or may impact BES reliability).

[143] *See* NERC Comments at 14.

scheme under Reliability Standard CIP-008-5, as well as ICS-CERT or its successor.[144] Reporting directly to E-ISAC and ICS-CERT will result in cyber threat information being provided to the organizations best suited to analyze and, to the extent necessary, timely inform responsible entities of cyber threats. In addition, reporting directly to E-ISAC and ICS-CERT addresses the concerns discussed above regarding the confidentiality of reported Cyber Security Incident information. We also find that it is reasonable for NERC to file annually an anonymized report providing an aggregated summary of the reported information, similar to the ICS-CERT annual report. The annual report will provide the Commission, NERC, and the public a better understanding of any Cyber Security Incidents that occurred during the prior year without releasing information on specific responsible entities or Cyber Security Events.

91. Therefore, we conclude that the minimum set of attributes to be reported should include: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident. NERC may augment the list should it determine that additional information would benefit situational awareness of cyber threats. As discussed above, we also conclude that NERC should

[144] The DHS ICS-CERT is undergoing a reorganization and rebranding effort. In the event that ICS-CERT no longer exists, its successor will assume the role as incident report recipient.

establish a reporting timeline that provides for notice based upon the severity of the event and the risk to BES reliability, with updates to follow initial reports. We also support the adoption of an online reporting tool to streamline reporting and reduce burdens on responsible entities to the extent the option is available.[145]

E. Other Issues

1. Comments

92. NYPSC supports the NOPR proposal, but notes that if the Commission adopts the NOPR proposal, "the only additional information that state entities would gain is an annual compilation of incidents reported to federal entities."[146] NYPSC claims that an annual report would not provide states with sufficient information on a timely basis so that they can ensure that corrective actions can be taken. Therefore, NYPSC argues that appropriate state entities should also be provided with the cyber reporting information when it is filed with the "federal authorities."

93. Microsoft raises a concern that the NOPR proposal is not clear as to whether the modified CIP Reliability Standards would apply to responsible entities that use a commercial cloud service to operate cloud-based BES Cyber Systems. Specifically, Microsoft requests that the Commission "confirm that cloud service providers that

[145] An online reporting tool will streamline the effort and allow for direct input into a database for a faster turnaround to those that may need to know about the information. For example, *see* https://www.us-cert.gov/forms/report.

[146] NYPSC Comments at 4-5.

provide services to Registered Entities are not required to register with NERC based on their provision of [cloud-based] services, and … are not responsible for compliance with the CIP Reliability Standards."[147] Microsoft asserts that clarifying the status of cloud service providers is important to foster technical innovation.

2. Commission Determination

94. While we appreciate NYPSC's interest in receiving Cyber Security Incident reports when reported to E-ISAC and ICS-CERT, state entities will have access to the same information that is reported to the Commission (i.e., the annual, anonymized summary). Should a state entity determine that it requires additional information from a responsible entity under its jurisdiction, the state entity can work within its own jurisdiction to procure additional information. Our directive is intended to enhance the quality of information received by E-ISAC and ICS-CERT, and directing additional sharing with state entities is outside the scope of this proceeding.

95. We decline to grant Microsoft's requested clarification regarding the potential registration status of cloud service providers because it is outside the scope of this proceeding. Specifically, Microsoft's requested clarification addresses a question regarding registration of cloud service providers under the NERC functional model, as opposed to the specifics of enhanced Cyber Security Incident reporting. The purpose of this proceeding is not to make a determination regarding the registration status of cloud service providers and we have not received input from other interested entities.

[147] Microsoft Comments at 1.

III. Information Collection Statement

96. The FERC-725 information collection requirements contained in this Final Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[148] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[149] Upon approval of a collection 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. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

97. The Commission will submit these proposed reporting requirements to OMB for its review and approval under section 3507(d) of the PRA because the Final Rule results in nonsubstantive/non-material changes in paperwork burden. The Final Rule directs NERC to make Cyber Security reporting changes across all applicable Reliability Standards. These proposed changes will be covered by the FERC-725 information collection (Certification of Electric Reliability Organization; Procedures for Electric

[148] 44 U.S.C. 3507(d) (2012).

[149] 5 CFR 1320.11 (2017).

Reliability Standards) [OMB Control No. 1902-0225]). FERC-725 includes the ERO's overall responsibility for developing Reliability Standards to include any Reliability Standards that relate to Cyber Security Incident reporting. There will be no change to the Public Reporting Burden as it affects the FERC-725 information collection.

98. Comments are solicited on the Commission's need for the information proposed to be reported, whether the information will have practical utility, 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.

99. Internal review: The Commission has reviewed the approved changes and has determined that the changes are necessary to ensure the reliability and integrity of the Nation's Bulk-Power System.

100. 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].

101. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-8528, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to:

oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM18-2-000 and OMB Control Number 1902-0225.

IV. Regulatory Flexibility Act Analysis

102. The Regulatory Flexibility Act of 1980 (RFA)[150] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.

103. By only proposing to direct NERC, the Commission-certified ERO, to develop modified Reliability Standards for Cyber Security Incident reporting, this Final Rule will not have a significant or substantial impact on entities other than NERC. Therefore, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

104. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

V. Environmental Analysis

105. 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.[151] The Commission has categorically excluded certain

[150] 5 U.S.C. 601-612.

[151] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

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.[152] The actions proposed herein to augment current reporting requirements fall within this categorical exclusion in the Commission's regulations.

VI. Document Availability

106. 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.

107. 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. 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

[152] 18 CFR 380.4(a)(2)(ii) (2017).

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.

VII. Effective Date and Congressional Notification

108. The Final Rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined that this Final Rule imposes no substantial effect upon either NERC or NERC registered entities[153] and, 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. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[153] 5 U.S.C 804(3)c

Appendix
Commenters

Jonathan Appelbaum (Appelbaum)
American Public Power Association, Electricity Consumers Resource Council, and Transmission Access Policy Study Group (Trade Associations)
Applied Control Solutions (ACS)
Arizona Public Service Company (APS)
Bonneville Power Administration (BPA)
Edison Electric Institute and National Rural Electric Cooperative Association (EEI/NRECA)
Douglas E. Ellsworth (Ellsworth)
Energy Sector Security Consortium (EnergySec)
Eversource Energy Service Company (Eversource)
Foundation for Resilient Societies (Resilient Societies)
Frank Gaffney (Gaffney)
Idaho Power Company (Idaho Power)
International Transmission Company (ITC)
ISO/RTO Council (IRC)
Isologic LLC (Isologic)
Jerry Ladd (Ladd)
Large Public Power Council (LPPC)
Mary D. Lasky (Lasky)
Michael Mabee (Mabee)
Garland T. McCoy (McCoy)
Microsoft Corporation (Microsoft)
New York Public Service Commission (NYPSC)
North American Electric Reliability Corporation (NERC)
NRG Energy (NRG)
Fred Reitman (Reitman)
Preston L. Schleinkofer (Schleinkofer)
Mark S. Simon (Simon)
Karen Testerman (Testerman)
U.S. Chamber of Commerce (Chamber)

164 FERC ¶ 61,023
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Kevin J. McIntyre, Chairman;
Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

North American Electric Reliability Corporation Docket No. RR17-6-000

ORDER APPROVING IN PART AND DENYING IN PART REVISIONS TO NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION RULES OF PROCEDURE AND REQUIRING COMPLIANCE FILING

(Issued July 19, 2018)

1. On June 26, 2017, North American Electric Reliability Corporation (NERC) filed a petition requesting approval of proposed amendments to section 600 (Personnel Certification) and section 900 (Training and Education) of the NERC Rules of Procedure. Pursuant to section 215(f) of the Federal Power Act (FPA) and section 39.10 of the Commission's regulations, subject to the exceptions discussed herein, the Commission conditionally approves NERC's petition.[1] The Commission also directs NERC to submit a compliance filing within 120 days of the date of this order to address our concerns as discussed below.

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Section 215(c) of the FPA establishes the requirements for ERO certification, specifying that the ERO must have the ability to develop and enforce Reliability Standards that provide for an adequate level of reliability of the Bulk-Power System. Section 215(c)(2) also requires the ERO to have rules that, *inter alia*, (1) assure its independence of the users and owners and operators of the Bulk-Power System, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure; and (2) provide reasonable notice and opportunity for public

[1] 16 U.S.C. § 824o(f) (2012); 18 C.F.R. § 39.10(a) (2017).

comment, due process, openness, and balance of interests in developing Reliability Standards and otherwise exercising its duties.[2]

3. Section 215(f) provides that the ERO shall file with the Commission any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose. Similarly, the Commission, upon its own motion or complaint, may propose a change to the rules of the ERO. A proposed rule or proposed rule change shall take effect upon a finding by the Commission "after notice and opportunity for comment that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest and satisfies the requirements of subsection (c)."[3]

4. On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA governing electric reliability.[4] In July 2006, the Commission certified NERC as the ERO.[5]

II. NERC's Petition

5. NERC states that the purpose of the proposed revisions is to: (1) clarify the scope of NERC's Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (2) streamline and align the language of the NERC Rules of Procedure with current practices.[6] NERC explains that the proposed changes to section 600 and 900 of the NERC Rules of Procedure are part of a comprehensive review to modernize and align the language of the Rules of Procedure with current ERO practices, specifically by delineating the responsibilities, governance and scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program. NERC also contends that the proposed revisions streamline the

[2] 16 U.S.C. § 824o(c)(2)(A), (D) (2012).

[3] 16 U.S.C. § 824o(f) (2012).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] NERC Petition at 1.

Rules of Procedure by eliminating detailed programmatic requirements duplicated in existing program manuals for the ERO.[7]

6. NERC states that the proposed changes to section 600 of the Rules of Procedure relate to the scope, structure, and responsibilities of the Personnel Certification Program. In proposed section 601, NERC clarifies that the purpose of the Personnel Certification Program is to (1) provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards and principles for Bulk-Power System operations; (2) administer a system operator certification exam; and (3) award the certification credential to system operators who pass the examination. NERC also proposes to revise section 601 to state that the NERC Reliability Standards specify which personnel require certification pursuant to the NERC Personnel Certification Program.

7. NERC proposes to consolidate section 602 (Structure of ERO Personnel Certification Program) and section 603 (Examination and Maintenance of NERC System Operator Certification Credentials), leaving section 603 as a placeholder. Specifically, NERC proposes to delete the governance authority and structure of the Personnel Certification and Governance Committee (PCGC) provisions, stating that this information is addressed verbatim in the PCGC charter, which is reviewed by NERC annually for updates and revisions and is approved by the NERC Board of Trustees.[8] NERC also specifies in revised section 602 that the PCGC must develop a certification program manual and outlines the mandatory elements of this manual.[9]

8. NERC proposes to eliminate programmatic details concerning the certification program from the Rules of Procedure, stating that the provisions are duplicated verbatim in the Personnel Certification Program manual and that the proposed revisions will allow program participants and NERC staff to only consult one resource for certification requirements.

9. Specifically, NERC contends that current section 603 contains procedural requirements for obtaining the system operator certification, which are duplicated

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[7] *Id.* at 3.

[8] *Id.* at 5.

[9] In its Petition, NERC uses different terms when referring to the manual referenced in section 600 of the NERC Rules of Procedure, including "certification program manual," "Personal Certification and Governance manual," and "Personnel Certification Program manual." On NERC's website, the manual is titled "System Operator Certification Program Manual." For purposes of this order, we will use the term "Personnel Certification Program manual."

verbatim in the Personnel Certification Program manual. For this reason, NERC proposes to delete section 603 in its entirety and revise section 602 to note that the manual must include "requirements for administering the system operation examinations," "requirements for exam eligibility," "requirements for awarding the Certification Credential," and "requirements for Certification Credential maintenance."[10]

10. NERC proposes to delete the programmatic detail in section 604 (Dispute Resolution Process) and section 605 (Disciplinary Action) and cross-reference the same requirements in the Personnel Certification Program manual.[11] NERC explains that the Personnel Certification Program manual is reviewed regularly for updates and revisions are presented to the NERC Board of Trustees. NERC notes that during the revision development process, stakeholders questioned whether the removal of these requirements from the Rules of Procedure would deprive stakeholders of the public notice and comment opportunities mandated for proposed changes to the Rules of Procedure under section 215(f). NERC states that "Section 215 of the FPA, the [Rules of Procedure] and NERC Bylaws do not require NERC to provide a separate, formal public notice and opportunity to comment on changes to the Personnel Certification Program manual."[12] NERC further notes that "[u]nder Section 215, due process requirements apply to (1) the development of Reliability Standards, (2) changes to ERO rules and (3) penalties for violations of Reliability Standards."[13]

11. In section 606, the proposed revisions clarify that the PCGC develops policies and procedures to protect the integrity of the certification exam administered under the Personnel Certification Program. NERC states that revised section 607 includes proposed ministerial changes to the types of information maintained and published about the Personnel Certification Program.[14] In section 608, NERC proposes to remove the requirement to include a statement of nondiscrimination in program announcements.[15] NERC proposes to revise section 609 to clarify that the exams administered pursuant to

[10] *Id.* at 6.

[11] *Id.*

[12] *Id.* at 7.

[13] *Id.*

[14] *Id.* at 8.

[15] *Id.*

the Personnel Certification Program are solely designed to measure essential knowledge relating to NERC Reliability Standards and general principles of the Bulk-Power System.

12. NERC proposes to revise section 900 to clarify the scope and governance structure of the Training and Continuing Education Programs.[16] Specifically, in section 901, NERC proposes to streamline the scope of the Training and Education Program to oversee the coordination and delivery of training materials for (1) ERO Enterprise staff supporting statutory and delegation-related activities; and (2) Bulk-Power System industry participants consistent with ERO functional program requirements. In section 902, NERC proposes revisions to outline the governance structure of the Continuing Education Program by identifying the Personnel Subcommittee, which reports to the NERC Operating Committee, as the governing body. NERC also proposes to designate the Personnel Subcommittee, which reports to the NERC Operating Committee, as responsible for developing and updating a manual that describes various requirements related to continuing education providers and audits.[17]

III. Notice and Responsive Pleadings

13. Notice of NERC's petition was published in the *Federal Register*, 82 Fed. Reg. 30,852 (2017), with interventions and protests due on or before July 17, 2017. No motions to intervene were filed.

14. On July 17, 2017, Alberta Electric System Operator, California Independent System Operator Corporation, The Independent Electricity System Operator, ISO New England, Inc., and PJM Interconnection, LLC (collectively, Protesters) submitted comments objecting to aspects of NERC's filing. Protesters assert that although changes are needed to the NERC Rules of Procedure, Protesters disagree with NERC's proposed changes as written and the rationale supporting those proposed changes.[18] First,

[16] *Id.* at 9.

[17] The manual referenced in section 900 of the NERC Rules of Procedure is the Continuing Education Administrative Manual, which is separate from the Personnel Certification Program manual referenced throughout section 600 of the NERC Rules of Procedure.

[18] Protestors' Comments at 1.

Protesters argue that because Reliability Standard PER-005-2[19] is now an enforceable NERC Reliability Standard, the NERC Continuing Education program is redundant and should be eliminated.[20] Second, Protesters argue that provisions that relate to compliance with Reliability Standards should not be removed from the Rules of Procedure, particularly where the provisions relate to Reliability Standard PER-003-1 (Operating Personnel Credentials).[21] Finally, Protesters argue that certain other proposed sections and references should be rejected or deleted because they are redundant.[22]

15. On October 17, 2017, NERC filed a motion for leave to answer and an answer. In the answer, NERC states that the Personnel Certification Program and the Continuing Education Program are not redundant with PER-005-2. NERC also highlights the different purposes served by the Reliability Standards related to system operator certification and training and NERC's separate certification, education and training programs in the Rules of Procedure.

IV. Procedural Matters

16. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2017), prohibits an answer to a protest unless ordered by the decisional authority. We accept NERC's answer because it provides information that is useful in our decision-making process.

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[19] The purpose of Reliability Standard PER-005-2 is to "ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach." Reliability Standard PER-005-2, Purpose. https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-005-2&title=Operations%20Personnel%20Training&jurisdiction=United States.

[20] Protesters' Comments at 2.

[21] The purpose of Reliability Standard PER-003-1 is to "ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System." Reliability Standard PER-003-1, Purpose. https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-003-1&title=Operating%20Personnel%20Credentials&jurisdiction=United States.

[22] Protesters assert that section 902 of the NERC Rules of Procedure should be rejected and that references to NERC's Continuing Education Program, Continuing Education Hours, and Re-Certification should be deleted. Protesters' Comments at 2-4.

V. Discussion

17. We approve NERC's proposed revisions to sections 601, 602, 606, 607, 608 and 609, as well as sections 901 and 902 of NERC's Rules of Procedure. Pursuant to section 215(f) of the FPA, we find that the proposed revisions we approve are just, reasonable, not unduly discriminatory or preferential, and in the public interest and that they satisfy the requirements of section 215(c) of the FPA. The proposed streamlining and clarifications set forth in these provisions improve the efficiency and clarity of the NERC Rules of Procedure.

18. However, we deny NERC's proposed revisions with regard to sections 603, 604, and 605 of the Rules of Procedure. We disagree with NERC's characterization of the proposed modifications to section 603, 604 and 605 as "programmatic detail" that can be eliminated from the Rules of Procedure. Rather, these provisions pertain to the rights, obligations, and procedures regarding the suspension of an operator's certification (section 603); resolving disputes arising in the certification process through a dispute resolution process (section 604); and initiating disciplinary actions against operators for matters such as "willful, gross, and/or repeated violation" of Reliability Standards or performance of duties as a certified system operator (section 605). If these provisions were removed from the NERC Rules of Procedure and remain only in a NERC manual, they would be subject to further change with minimal, if any, stakeholder input and without Commission review. This is not appropriate because changes in the provisions for suspension, dispute resolution, or disciplinary actions could have a significant impact on a stakeholder's or individual's rights and obligations. NERC provides no explanation as to why it regards these provisions as "programmatic detail" that can be removed from the Rules of Procedure. Accordingly, we conclude that Section 603, 604, ad 605 should remain as part of the NERC Rules of Procedure. This decision will continue to allow for stakeholder input and opportunity for Commission review in the development of modifications to the NERC Rules of Procedure – and ultimately provide a greater level of certainty to stakeholders and individuals.

19. Moreover, NERC previously identified the provisions of section 600 as "substantive" in explaining why NERC proposed to move them from an appendix (i.e., former Appendix 6) of the Rules of Procedure to current sections 603, 604, and 605, which the Commission approved.[23] At that time, NERC explained that "the substantive provisions of Appendix 6 [of the Rules of Procedure] are being moved into [Rule of

[23] NERC, Petition, Docket No. RR12-8-000, at 18-21, 83-84 (filed May 7, 2012) (May 7, 2012 Petition); *North American Electric Reliability Corp.*, 141 FERC ¶ 61,241 (2012) (approving, *inter alia*, shift of certain provisions in NERC Rules of Procedure, Appendix 6 "System Operator Certification Program Manual" to section 600, including provisions related to dispute resolution and disciplinary action).

Procedure section] 600."[24] NERC also distinguished the substantive provisions that were moved into section 600 from other provisions in Appendix 6 that were simply deleted by stating that "Appendix 6 is being deleted from the [Rules of Procedure] because it contains a significant amount of administrative detail about the System Operator Certification Program that does not rise to the level of an 'ERO Rule'…"[25] NERC does not explain why it now regards the once-considered "substantive" provisions to constitute "programmatic detail" that can be removed. Rather, NERC asserts that the provisions are duplicative of NERC's Personnel Certification Program manual. This, however, is an insufficient alternative as the NERC manuals are not submitted for Commission review and can be modified by NERC with minimal stakeholder participation. As discussed above, this is an inadequate approach for matters impacting, for example, a certified operator's possible suspension or ability to employ dispute resolution procedures. Accordingly, we deny NERC's proposal with respect to sections 603, 604, and 605 of the Rules of Procedure.

20. We direct NERC to submit a compliance filing within 120 days of the date of this order, removing the proposed revisions and restoring sections 603, 604, and 605.[26] We also direct NERC to correct certain typographical errors in proposed sections 600 and 900.[27]

21. Finally, in approving NERC's proposed revisions to sections 901 and 902 concerning the coordination and delivery of learning materials, resources and activities for training and education, and manual requirements for NERC's Continuing Education Program, we acknowledge Protesters' concerns about the continuing relevance of that program. However, we find Protesters' assertion that Reliability Standard PER-005-2

[24] May 7, 2012 Petition at 84.

[25] *Id.*

[26] As referenced above, Protesters expressed concern that NERC's proposal to move provisions related to maintaining the NERC System Operator Certification Credential to committee charters and manuals may impact compliance with Reliability Standard PER-003-1 and thus the due process rights of registered entities. Protesters' Comments at 2-3. We note that the denial of the revisions to sections 603, 604, and 605, should resolve the Protesters' concern on this matter.

[27] Specifically, in section 602.6 "displicinary" should be changed to "disciplinary." In section 606.2.1, "access" should be changed to "assess." In section 902.3, "The PS shall develop and update, as necessary, manual, approved…" should be "The PS shall develop and update, as necessary, a manual, approved…"

renders section 902, and references to the Continuing Education Program, re-certification and related items, unnecessary and obsolete, to be beyond the scope of this proceeding.[28]

The Commission orders:

(A) NERC's revised Rules of Procedure are hereby conditionally approved, with the exceptions discussed in the body of this order.

(B) NERC is hereby directed to submit a compliance filing within 120 days from the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

[28] Protesters' Comments at 2, 4.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR18-4-000

June 28, 2018

North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Attention: Alexander Kaplen
Attorney for North American Electric Reliability Corporation

Reference: Amended Compliance and Certification Committee Charter

Dear Mr. Kaplen:

On March 15, 2018, North American Electric Reliability Corporation (NERC) submitted an amended Compliance and Certification Committee (CCC) Charter to reflect the participation of CCC observers in NERC audits of Regional Entities in accordance with Appendix 4 of the NERC Rules of Procedure.

Notice of this filing was issued on March 16, 2018, with protests and interventions due on or before April 5, 2018. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No adverse comments were received.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307, 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. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. 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.

Sincerely,

Penny S. Murrell

Penny S. Murrell, Director
Division of Electric Power Regulation – Central

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

July 12, 2018

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	July 19, 2018 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://ferc.capitolconnection.org/ using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1046th - MEETING

OPEN MEETING

July 19, 2018

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD18-1-000	Agency Administrative Matters
A-2	AD18-2-000	Customer Matters, Reliability, Security and Market Operations
		ELECTRIC
E-1	RM18-2-000	Cyber Security Incident Reporting Reliability Standards
E-2	RM18-15-000	Revisions to Parts 45 and 46 of the Commission's Regulations
E-3	RR17-6-000	North American Electric Reliability Corporation
E-4	EL15-67-003 ER15-2562-002 ER17-950-003 EL17-68-000 EL17-84-001 EL17-90-001 EL17-94-000 ER18-579-002 ER18-680-000 (Not Consolidated)	Linden VFT, LLC v. PJM Interconnection, L.L.C. PJM Interconnection, L.L.C. PJM Interconnection, L.L.C. Linden VFT, LLC v. PJM Interconnection, L.L.C. PJM Interconnection, L.L.C. Linden VFT, LLC v. Public Service Electric and Gas Company and PJM Interconnection, L.L.C. New York Power Authority v. PJM Interconnection, L.L.C. and PJM Transmission Owners in their Collective Capacity PJM Interconnection, L.L.C. PJM Interconnection, L.L.C.
E-5	EL18-146-000	KCP&L Greater Missouri Operations Company
E-6	EL15-95-003	Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, L.L.C. and Certain Transmission Owners Designated under CTOA RS FERC No. 42

GAS

G-1	OR14-4-002	Guttman Energy, Inc. and PBF Holding Company LLC v. Buckeye Pipe Line Company, L.P. and Laurel Pipe Line Company, L.P.

HYDRO

H-1	OMITTED	
H-2	P-2114-296	Public Utility District No. 2 of Grant County, Washington
H-3	P-12611-011	Verdant Power, LLC

CERTIFICATES

C-1	CP17-80-000	Columbia Gas Transmission, LLC
C-2	CP18-10-000	Texas Eastern Transmission, LP
C-3	CP17-441-000 CP17-441-001	Northwest Pipeline LLC
C-4	CP18-66-000 CP18-69-000	Gulf South Pipeline Company, LP Tristate NLA, LLC
C-5	CP18-5-001	Constitution Pipeline Company, LLC
C-6	CP16-22-001 CP16-23-001 CP16-24-001 CP16-102-001	NEXUS Gas Transmission, LLC Texas Eastern Transmission, LP DTE Gas Company Vector Pipeline L.P.
C-7	CP16-486-001	Millennium Pipeline Company, L.L.C.

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through http://ferc.capitolconnection.org/. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for

the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit http://ferc.capitolconnection.org/ or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

July 2018
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its July 19, 2018 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1 – Press Release

FERC proposes a rule

E-2, *Revisions to Parts 45 and 46 of the Commission's Regulations*, Docket No. RM18-15-000. This Notice of Proposed Rulemaking proposes to revise parts 45 and 46 of the Commission's regulations related to interlocking officers and directors. Among other proposed changes, the Commission proposes to update its regulations to reflect statutory changes regarding the circumstances in which an applicant requires Commission authorization to hold interlocking positions between public utilities and securities underwriters and marketers. The Commission also proposes to revise its regulations concerning late-filed applications and informational reports. The Commission further proposes to revise its regulations to clarify that an interlock holder is not required to file a notice of change when merely changing positions within a holding company structure.

FERC approves, in part, and denies, in part, proposed reliability rule revisions

E-3, *North American Electric Reliability Corporation*, Docket No. RR17-6-000. This order approves, in part, and denies, in part, proposed revisions to NERC's Rules of Procedure sections 600 (Personnel Certification) and 900 (Training and Education). Specifically, the order directs NERC to restore sections 603, 604, and 605 that NERC proposes for deletion. These provisions pertain to (1) procedures for suspension of an operator's certification (section 603); (2) dispute resolution process (section 604); and (3) disciplinary action (section 605). The order determines that these provisions are not "programmatic detail" that can be transferred to NERC manuals but, rather, are substantive provisions that should remain in the NERC Rules of Procedure.

FERC establishes settlement judge procedures

E-4, *Linden VFT, LLC v. PJM Interconnection, LLC*, Docket No. EL15-67-003. The order establishes settlement judge procedures to allow the parties challenging the assignment of cost responsibilities for certain projects an opportunity to negotiate a settlement agreement in light of changed circumstances since the cost responsibilities were first set.

FERC grants a petition for declaratory order

E-5, *KCP&L Greater Missouri Operations Company*, Docket No. EL18-146-000. This order grants Greater Missouri's petition for declaratory order, finding that the proposed payment of dividends described in the petition complies with section 305(a) of the Federal Power Act.

FERC grants rehearing, establishes paper hearing procedures

E-6, *Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, LLC*, Docket No. EL15-95-003. The order grants rehearing of the Commission's April 22, 2016 order that previously denied a complaint filed by the state commissions that had contended the use of the solution-based distribution factor method to assign cost responsibility for a portion of the costs of certain transmission projects was unjust, unreasonable, or unduly discriminatory or preferential. The order further establishes paper hearing procedures to determine the just and reasonable rate.

FERC denies rehearing

G-1, *Guttman Energy, Inc. and PBF Holding Company, LLC v. Buckeye Pipe Line Company, LP and Laurel Pipe Line Company, LP*, Docket No. OR14-4-002. This order denies Buckeye's request for rehearing of Opinion No. 558 that revoked Buckeye's market-based rate authority for its Harrisburg and Pittsburgh, Pennsylvania, destination markets.

FERC denies rehearing

H-2, *Public Utility District No. 2 of Grant County, Washington*, Project No. 2114-296. This order denies rehearing of the Commission's order authorizing Grant PUD to allow Stockdale, Inc. to expand the Vantage Marina to accommodate seven additional watercraft, increasing the total capacity to 17 slips on the Priest Rapids Project No. 2114. The project, which includes both the Priest Rapids and Wanapum dams and associated reservoirs, is located on the mid-Columbia River in portions of Grant, Yakima, Kittitas, Douglas, Benton, and Chelan counties, Washington.

FERC denies rehearing

H-3, *Verdant Power, LLC*, Project No. 12611-011. This order denies Verdant's request for rehearing of Commission staff's May 3, 2018 order denying Verdant's request for a five-year extension of its pilot license for the Roosevelt Island Tidal Energy Project No. 12611. The order affirms staff's finding that, barring any extraordinary circumstances, 10 years should be enough time to complete a testing program and make a decision on whether to file an application for a build-out license. The unconstructed 1,050-kilowatt project would be located in the East River in New York County, New York.

FERC authorizes, subject to conditions, new interstate natural gas infrastructure

C-1, *Columbia Gas Transmission, LLC*, Docket No. CP17-80-000. This order authorizes, subject to conditions, a certificate of public convenience and necessity to Columbia to construct and operate its Eastern Panhandle Expansion Project that would provide up to 47,500 dekatherms per day of incremental firm transportation service to serve markets in West Virginia. To provide the incremental services, Columbia proposes to construct and operate approximately 3.37 miles of 8-inch-diameter pipeline, commencing with interconnections at Columbia's Line 1804 and Line 10240 in Fulton County, Pennsylvania, and extending through Washington County, Maryland, to a point of delivery with the local distribution system of Mountaineer Gas Company, the project shipper, in Morgan County, West Virginia.

FERC authorizes, subject to conditions, new interstate natural gas infrastructure

C-2, *Texas Eastern Transmission, LP*, Docket No. CP18-10-000. The order grants Texas Eastern a certificate of public convenience and necessity, subject to conditions, to construct and operate Texas and Louisiana Market Expansion projects to provide 157,000 dekatherms per day of incremental firm transportation service from receipt points on Texas Eastern's interstate pipeline system in the West Louisiana Access Area to delivery points in Texas Eastern's West Louisiana Access Area and South Texas Access Area. The order also authorizes Texas Eastern to use existing system rates as initial recourse rates for firm service on the projects and grants a predetermination that it may roll project costs into its system rates in its next Natural Gas Act section 4 rate case. In addition, the order authorizes Texas Eastern to establish and charge an initial incremental electric power cost rate for firm service on the Texas Project.

FERC authorizes abandonment and replacement of interstate pipeline facilities

C-3, *Northwest Pipeline LLC*, Docket No. CP17-441-000. The order authorizes the abandonment of 5.9 miles of existing 8-inch diameter pipeline and grants a certificate of public convenience and necessity to construct 5.9 miles of 20-inch diameter replacement pipeline to Northwest Pipeline for its proposed North Seattle Lateral Upgrade Project.

Northwest will construct the replacement pipeline in the existing easement. The project is designed to provide 159,299 dekatherms per day of additional firm transportation service on the North Seattle Lateral to Puget Sound Energy, an existing customer. The order also authorizes Northwest to abandon and replace 0.17 miles of 16-inch looping pipeline and to modify appurtenant facilities, including the North Seattle/Everett meter station, Northwest's mainline, and relocating an existing pig launcher and receiver to accommodate the increased capacity.

FERC authorizes abandonment, determines certain facilities non-jurisdictional

C-4, *Gulf South Pipeline Company, LP,* Docket No. CP18-66-000. The order approves Gulf South's request to abandon by sale to Tristate NLA, LLC (Tristate) approximately 189.8 miles of various diameter gathering and transmission pipelines, associated meter and regulator stations, and other related facilities located in Texas and Louisiana. In addition, the order grants Tristate's petition for declaratory order requesting that the Commission find, upon transfer to Tristate, that the facilities will be exempt from the Commission's jurisdiction. Specifically, the order finds that, upon transfer to Tristate: (1) approximately 155.8 miles of pipeline and appurtenant facilities will perform a gathering function; (2) 15.2 miles of pipelines and appurtenant facilities will be operated as a Hinshaw pipeline; and (3) 18.8 miles of pipeline will operate as an intrastate pipeline.

FERC denies rehearing

C-5, *Constitution Pipeline Company, LLC,* Docket No. CP18-5-001. The order denies rehearing of the Commission's January 11, 2018 determination that the New York State Department of Environmental Conservation did not waive its authority under section 401(a)(1) of the Clean Water Act to issue or deny a water quality certification for the Constitution Pipeline Project. The order (a) refutes the argument that the Commission must determine case-by-case what is the "reasonable period of time" for state action on a section 401 application, (b) reaffirms the Commission's longstanding determination that the reasonable period of time for state action is the full year allowed by the Clean Water Act, and (c) reaffirms the Commission's conclusion that the withdrawal and resubmission of a section 401 application restarts the reasonable period of time for state action.

FERC dismisses and denies rehearing requests

C-7, *Millennium Pipeline Company, LLC,* Docket No. CP16-486-001. The order addresses two requests for rehearing of the Commission's November 28, 2017 certificate of public convenience and necessity authorizing Millennium to construct and operate the Eastern System Upgrade Project, comprising of pipeline, compression, and ancillary facilities designed to provide up to 223,000 dekatherms per day of firm transportation service from an existing compressor station to an existing interconnect with Algonquin

Gas Transmission, LLC. Specifically, the order dismisses certain requests for rehearing for failing to set forth with specificity the basis of their respective objections to the Commission's order. The order also denies the remaining rehearing requests, finding that, among other things, the project is not overbuilt; the initial order did not improperly segment the project from other nearby projects; and the initial order did not improperly assess the project's greenhouse gas emissions.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Risk of Internet Accessible Cyber Assets

Primary Interest Groups
Transmission Operators (TOPs)
Transmission Owners (TOs)
Generation Operators (GOPs)
Generation Owners (GOs)
Distribution Provider (DPs)

Problem Statement
An electronic access point connected to the internet from a low-impact facility for remotely accessing a capacitor bank was compromised by unauthorized internet users for seven months prior to discovery.

Details
A registered entity discovered a compromised electronic access point connected to the internet from a low-impact facility. The access point was originally intended to be temporary and was installed by a SCADA Manager who subsequently left the entity without providing adequate documentation and turnover to the next SCADA Manager. The access point was misidentified as a remote terminal unit (RTU) with an end-of-life (EOL) operating system and left in place. Unauthorized personnel accessed the cyber asset for seven months before the registered entity became aware of the compromise. Because the device was identified as an EOL system, the compromised system was not maintained (patched, monitored, etc.) by the registered entity and was thus more susceptible to exploitable vulnerabilities.

The initial compromise resulted from an unauthorized internet user guessing via a "brute force"[1] method the weak password for the administrators' account, which permitted remote access. The compromised cyber asset was used over a seven-month period as a mail relaying (SMTP) and remote desktop (RDP) scanner.[2] Additionally, the IP address and credentials for the cyber asset were posted on a Russian-based media site, and the cyber asset was subsequently infected with ransomware.[3] The compromise was discovered after support staff could not remotely access the cyber asset. The purpose of the internet-connected access point was to remotely access and operate the capacitor banks to ensure the reliability of the system. Upon looking into the matter further, personnel discovered that the cyber asset was compromised with ransomware, so the registered entity immediately powered off the cyber asset.

[1] "Brute forcing" is an automated method of attempting authentication with many different passwords until the attacker is able to successfully login to the system
[2] A network scanner performs a scan on a network and collects an electronic inventory of the systems and the services for each device on the network. In this case, the server was used to scan for open SMTP (Simple Mail Transfer Protocol) servers and RDP (Remote Desktop Protocol) servers for potential compromise.
[3] See the NERC Alert dated 6/7/2016 "Ransomware Extortion Poses Increasing Risk"

Forensic analysis on the compromised system identified several different scanning tools designed to locate remotely accessible RDP or SMTP servers along with text files containing IP addresses for the scanners to target. Although the attackers likely conducted reconnaissance on the local network to identify other vulnerable devices, the primary focus of their activity appears to identify other remote systems to target for attacks.

Corrective Actions

The registered entity removed the compromised device from service and performed forensic analysis to identify all malware on the affected device and determine agent(s) of the compromise, time lines, and reveal (to the most possible extent) the underlying activities and motives of the compromise. A virus scan was also performed on all devices at the same site as well as a review of logs on all of the devices to look for anomalous activity. Other locations were also scanned to determine whether they had similar installations or issues.

Lesson Learned

Cyber assets at low-impact facilities capable of remote internet connectivity are susceptible to unauthorized access from the Internet or unsecured networks if not properly secured. These remote access points are typically used to provide communication paths for monitoring and control purposes to maintain BES reliability. Remote connectivity that can provide unauthorized and potentially malicious access to systems that supply auxiliary power, power quality, voltage support, fault monitoring, and breaker control is of particular concern. Failure to develop and follow appropriate policies and procedures to control the installation and maintenance of cyber assets may create exploitable vulnerabilities that could negatively impact BES reliability.

In this case, installation of, inaccurate identification of, and failing to provide adequate security protections for a device connected to a registered entity's network led to the compromise of the device. There may be several practical lessons learned that can be derived from this event that apply to low-impact cyber assets and constitute good cyber security practices in general.

Policy and Procedure:

- Train employees and contractors on cyber security awareness, policy, and practices.
- Catalog cyber assets at low-impact facilities to determine use and facilitate accurate records.
- Consult with and obtain authorization from responsible IT departments as well as compliance and risk management groups to evaluate potential risks and impacts of internet-facing and internetworked cyber assets at low-impact facilities.
- Have personnel (e.g., operations, maintenance) who perform periodic on-site visits conduct cyber device inventory checks as part of routine safety and maintenance inspections. Consider using a checklist.
- Periodically re-evaluate risks and potential impacts of the inventoried cyber assets as new threats and vulnerabilities are revealed or vendor support is discontinued.

- An entity's IT department could use tools such as Shodan[4] and nmap[5] on the entity's own public IP space on a regular basis to verify only authorized ports are open to the internet.
- When an employee or contractor leaves the company or is terminated, ensure appropriate turnover and Knowledge Transfer processes occur.

Cyber Security practices to consider for low-impact facilities:

- Identify and secure cyber assets at low-impact facilities capable of remote connectivity.
- Where possible, implement network access controls within the system to prevent the installation of unauthorized hardware.
- Implement network segmentation into trust zones.
- Change default passwords with strong passwords on user accounts and administrative accounts and restrict operational use of administrative accounts. Implement MFA (multi-factor authentication) for all internet-facing resources that support these technologies
- Provide for a patch management plan for evaluating security patching for cyber assets at low-impact facilities
- Whenever practical, monitor the network for anomalous behavior.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis
Source of Lesson Learned:	Western Electric Coordinating Council
Lesson Learned #:	20180701
Date Published:	July 24, 2018
Category:	Transmission Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

[4] Shodan is an Internet site used to discover devices that are connected to the Internet, where they are located and who is using them.
[5] Nmap ("Network Mapper") is a free and open source (license) utility for network discovery and security auditing.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Preparing Circuit Breakers for Operation in Cold Weather

Primary Interest Groups
Generator Owners (GOs)
Generator Operators (GOPs)
Transmission Owners (TOs)
Transmission Operators (TOPs)

Problem Statement
After two sequential line faults, an entire substation and a 1,150 MW nuclear plant tripped off-line due to consecutive breaker failures during cold weather (4°F).

Details
Two sequential B-phase faults occurred on a 500 kV line, apparently due to icing. Three breakers subsequently experienced breaker failure (failure-to-trip) events, de-energizing an entire substation and tripping a large generating unit off-line. The first breaker (Breaker 1, a SF_6 breaker with hydraulic mechanism) opened properly for the first fault, but did not reclose correctly. Breaker 1 experienced a hydraulic mechanism malfunction and correctly reclosed on only two of its three phases. As a result, Breaker 1 was unable to respond to the second fault. After that, two other breakers (Breakers 2 and 3, SF_6 breakers with pneumatic trip/spring close mechanisms) were very slow to trip on B-phase. For Breakers 2 and 3, there was a failure of the center pole to clear the fault quickly enough due to cold temperatures.

Corrective Actions
For Breaker 1, a defective motor contactor was discovered and replaced and a full hydraulic service was performed on all three phases. A diagnostic service was also performed to ensure that the breaker was ready to be returned to service.

- There was no cost effective way identified to foretell or prevent the issues discovered with Breaker 1. This type of failure has not been a systemic problem at other locations. The entity is still evaluating counter-measures based on these findings and will continue to monitor the condition of this breaker using existing preventive maintenance guidelines.

For Breakers 2 and 3, the manufacturer engineered a fix consisting of additional thermostatically-controlled cabinet heaters that prevent moisture from freezing inside the pneumatic (air) control valve during cold-weather conditions. One breaker also needed repair to the trip-coil circuitry. The engineered fix and repairs were completed for both breakers. A diagnostic service was also performed to ensure that both breakers were ready to be returned to service.

- Application of the engineered short-term fix to Breakers 2 and 3 prevents future operational issues on B-phase pneumatic control valve during low-temperature conditions. The manufacturer is developing a long-term fix.

- There were two additional breakers from the same manufacturer at the same substation. The same short-term fix was also applied to those breakers.

Lessons Learned

Breakers have several cold-temperature-related failure mechanisms. A good practice is to annually (prior to first frost date for the location) perform pre-cold weather checks (seal condition, lubrication, pressures, dielectric, dryers, and adequate functioning heaters or heat tracing) for cold-sensitive components.

Other Cold Weather Breaker Issues

Hydraulic

- Sections that are normally at air pressure may pull contaminants in past seals as cooling pulls a vacuum there. If contaminated with water - ice gets in the works - can plug ports.
- If oil is breaking down, sludge may form that can also harden at cold temperatures.
- Hydraulic oil becomes more viscous as it gets colder; ensure oil used is rated for conditions colder than expected.
- Seals may shrink, harden or crack and leak, losing oil and pressure.
- If the design uses belt-driven pumps, belts may embrittle/crack. Belt shrinkage may cause axles to pull into misalignment (rubbing, dragging, seizing, belt coming off, belt failure, axle bearing failure, axle seal failure).

Gas / Air pressure operated

- Extreme cold reduces pressure (Ideal Gas Law PV = nRT). If pressure was already close to low end of operability, the cold will take it below (the compressor should cycle on to make up for that). Reduced pressure reduces the capacity of the breaker to interrupt an arc. Extra margin is needed for extreme cold.
- Seals may shrink, harden or crack and leak, losing gas and pressure. Sections that are normally at air pressure may pull contaminants, (including moisture which can freeze) in past seals as cold pulls a vacuum there.
- Compressor belts may embrittle and crack. Belt shrinkage may cause axles to pull into misalignment (e.g., rubbing, dragging, seizing, belt coming off, belt failure, axle bearing failure, axle seal failure). Air compressors need intakes that are protected from the elements (water and dust ingestion, freezing over) and the air water separator/dryer maintained (desiccant monitoring and replacement).
- SF_6 gas condenses to liquid at temperatures encountered in northern winters (-10°F/-23.3°C to -30°F/34.4°C depending on pressure, - generally between 95 and 70psig). This requires heaters to keep the SF_6 in a gaseous state.
- Heaters (and insulation) that do not provide complete coverage of the SF_6 volume (and tubing) may allow cold pockets for SF_6 condensation.

General/Mechanical

- Exposed mechanisms can be frozen over, requiring more force to break free and move initially.
- Differential expansion coefficients of materials can cause sliding surfaces to become tighter or seize if the outer material shrinks faster with cold than the inner surface. It is worse if lubrication is less than adequate or if grit has gotten in between surfaces.
- Lubricants thicken as they get colder. There is a viscosity limit; ensure the lubricant used is rated for more than the expected temperature range (cold and hot) since temperature records are broken in both directions eventually. If lubricant component separation occurs (reference other slow breaker LL), lubrication becomes less than adequate.

Cold weather impacts other substation, transmission, and generation equipment too. NERC Event Analysis is developing substation equipment Failure Modes and Mechanism (FMM) information that includes cold weather impacts. NERC conducts annual webinars on Winter Weather Preparedness for the industry.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis
Source of Lesson Learned:	Western Electric Coordinating Council
Lesson Learned #:	20180702
Date Published:	July 24, 2018
Category:	Transmission Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lessons Learned

Loss of Substation Data Circuits to SCADA

Primary Interest Groups:
Transmission Owners (TOs)
Transmission Operators (TOPs)
Balancing Authorities (BAs)
Reliability Coordinators (RCs).

Problem Statement:
While initiating a transfer of SCADA (Supervisory Control And Data Acquisition) from the company's alternate control center (ACC) to primary control center (PCC), an interruption of vendor-provided substation data circuits occurred that resulted in a temporary and partial loss of SCADA operating and monitoring capability for more than 30 minutes.

Details:
Data communication services are provided to a majority of the company's substations by a telecommunications service provider (referred to in this document as the TelCo). The remaining portion of substations use the company's internal network for data communications.

During a scheduled transfer of its SCADA from the ACC to the PCC, the company experienced a loss of all TelCo-provided remote substation data circuits for more than 30 minutes. The transfer was scheduled to begin during the late evening hours following a day of network maintenance (firewall upgrades), which required the successful transfer of SCADA from the PCC to the ACC.

Once the maintenance work had been completed, the company directed the TelCo to transfer all data circuits back to the PCC. Within minutes of the transfer process, it became evident that the reconnection phase of the process had failed. This resulted in a loss of operating and monitoring functionality for more than 30 minutes for the majority of the company's substations.

In accordance with its procedures, the company notified its RC and initiated callouts to staff key Bulk Electric System (BES) substations while continuing to monitor ties through all inter-control center communications protocol connections with neighboring TOPs. The TelCo, in turn, began investigating and trouble-shooting the event.

As a result of its investigation, the TelCo determined that it had experienced a major network outage that impacted its ability to test and map circuits during the reconnection process. The outage occurred just after the TelCo's test center had unmapped the Company data circuits from the alternate recovery path (ACC disconnect) and before they could be mapped to the primary path (PCC reconnect). This left all data circuits out of service. Furthermore, the investigation identified multiple hardware failures within the TelCo's network.

Approximately eight hours after the event first occurred, the TelCo reported that all network issues had been resolved and the affected data circuits had been restored.

Corrective Actions:
The company recommends these actions to address the issues that led to this event:

- Schedule future SCADA data circuit transfers during daytime hours on business days. This would facilitate and enhance response times in staffing BES substations. During daytime hours, substation technicians and electricians are typically available at work sites and do not have to report to work from home as would be the case for incidents occurring during nighttime hours. Accordingly, pertinent operating procedures to reflect the scheduling of SCADA data circuit transfers during the morning hours will need to be revised. This action would provide an additional internal control to ensure that SCADA data circuit transfers are appropriately scheduled.
- In collaboration with the TelCo, develop a script used to disconnect and reconnect SCADA data circuits that splits the process into several blocks. A block would have to be run and completed (disconnected and reconnected) before initiating another. This would significantly mitigate the risk of an outage to all of the TelCo-provided SCADA data circuits.

Lessons Learned:

- Events occurring during the nighttime hours present unique challenges due to the limited immediate availability of key personnel. By planning and scheduling maintenance activities that require critical steps (i.e., the transfer of SCADA data circuits from primary to alternate control centers and vice versa) during the daytime hours on business days, response times in staffing BES facilities to regain operational control can be significantly reduced.
- The transfer of SCADA circuits from one control center to another is a critical operation. Close collaboration with communication vendors who own and/or operate the circuits is essential in determining ways to manage and mitigate the risk of an event leading to the total disruption of data communications to substations.
- Additional considerations:
  - Consider redesigning communications systems such that the most critical BES substations communicate simultaneously with entirely separate physical paths (and possibly separate vendors) to both control centers, eliminating the need for any TelCo communication transfer activities.
  - When failing over, procedures should be in place that verify the soon-to-be active server/circuit has all critical components functioning.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20180801
Date Published:	August 7, 2018
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Firewall Failure After Time Limit Exceeded

Primary Interest Groups
Balancing Authorities (BAs)
Generation Operators (GOPs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs) that operate an Energy Management System (EMS)

Problem Statement
Due to a firmware error, a firewall stopped processing network traffic without proper failover after an internal run-time limit was exceeded. This resulted in persistent remote terminal unit (RTU) communication issues.

Details
A firewall firmware security patch issued by the firewall vendor was applied to an entity's equipment, which unknown to all parties at the time, contained a process runtime limit of 213.5 days.

After reaching reaching the 213.5 day limit of uptime, the entity experienced a loss of all SCADA-EMS RTU communications. The system operator called in-house SCADA-EMS support and started notifying all neighboring TOPs and requested assistance. The entity's SCADA-EMS Manager remoted into the SCADA-EMS system and verified that SCADA-EMS system processes were functioning but found there was a network issue causing loss of communication with the field RTUs. The entity's SCADA-EMS analyst arrived on site and verified that SCADA-EMS system was functioning normally, but found that an outside interface of an online polling firewall was blocking traffic; the online polling firewall software had failed. The network administrator attempted to failover to the backup firewall. This did not resolve the issue because both firewalls were experiencing the same firmware issue due to the similar uptimes of the firewall software. Both firewalls remained online and both were trying to process traffic.

The network administrator rebooted the backup polling firewall and shut down the outside interface on the online polling firewall. After that, all communication circuits began to be restored.

After investigation and discussion with the firewall vendor, it was determined that about two months prior to the event, the vendor had identified the runtime bug and notified their users via a blog post. The post gave detailed interim advice on how to check the elapsed uptime and to reboot the firewall "proactively" prior to hitting the limit while the vendor worked on a patch. A followup Field Notice about a week before the event provided additional details. Notification of the patch and and a link to it were provided in subsequent technical bulletin.

The entity had a focus on security patching. Security bulletins from the vendor were monitored and security patches were promptly tested and applied. In this case, the interim rebooting advice and eventual patch were provided in the vendor site blog, field notices, and technical bulletins, which were not processed with the same priority as security bulletins.

Corrective Actions

The entity rebooted the backup firewall then shut down the outside interface on the online polling firewall to force a failover. This restored network traffic and RTU communications.

Following the vendor interim advice, the entity then scheduled proactive reboots of the control center firewalls and other affected firewalls.

Later, the firewall firmware was upgraded to a new release that did not have the same limitation.

The entity now uses the same level of priority for review for technical bulletins as the security bulletins.

Lesson Learned

To prevent recurrence of the issue, maintain network devices on a planned schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates.

If available, entities should enroll in automated notification services for these updates.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	MRO – Event Analysis
Source of Lesson Learned:	Midwest Reliability Organization
Lesson Learned #:	20180802
Date Published:	August 7, 2018
Category:	Transmission Facilities

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Operational Fuel-Security Analysis

ISO new england

For Discussion

JANUARY 17, 2018
ISO-NE PUBLIC

Contents

Figures 3

Tables 3

Highlights 4

Executive Summary 6

Background 6

The Study 7

Key Takeaways 8

Next Steps 9

Background: The Changing Grid and New England's Fuel-Supply, Infrastructure, and Logistical Challenges 10

The Changing Grid 11

Logistical Uncertainties: Fuel Deliveries and Weather 14

Natural Gas Delivery Challenges: Infrastructure Constraints and Contracts 16

Operational Fuel-Security Analysis 18

Study Description 18

Overview of the Scenarios 22

Key Resource Assumptions 23

Methodology 28

Metrics: How System Stress Was Measured 28

Study Results 32

Reference Case 33

Single-Variable Scenarios 36

Combination Scenarios 40

Outage Scenarios 42

Key Findings 47

Conclusions 50

Outages 50

Stored Fuels: Imported LNG, Electricity Imports, and Dual-Fuel Capability 51

Logistics 52

Risk Trending in a Negative Direction 53

More Renewables Help, but Don't Eliminate the Risk 53

More Positive Outcomes 54

Next Steps 55

Appendix A: Detailed Results 56

Figures

Figure 1: 2015 Annual Fuel Mix Compared with Day of Highest Coal and Oil Generation in 2015 12

Figure 2: Winter LNG Deliveries to New England Interstate Pipelines 24

Figure 3: Winter 2024/2025 Supply of Pipeline Gas and LNG Compared to Use (Reference Case) 25

Figure 4: Hours of Emergency Actions under Modeled Scenarios, Ordered Least to Most 33

Figure 5: Projected Winter 2024/2025 Oil and LNG Use and Emergency Actions (Reference Case) 36

Figure 6: Ranges of OP 4 Hours in Single-Variable Cases 37

Figure 7: Ranges of OP 7 Hours in Single-Variable Cases 37

Figure 8: Projected Hours of Load Shedding due to Season-Long Outage of a Major Fuel or Energy Source (Reference Case Compared with the Max Scenario) 43

Figure 9: Magnitude of Load Shedding in Modeled Cases 49

Tables

Table 1: Renewable Resource Assumptions 27

Table 2: ISO Operating Procedure No. 4 Actions 30

Table 3: **Reference Case** Assumptions and Results 35

Table 4: Assumptions and Results for the Scenario with **More Renewables** Compared with the Reference Case 38

Table 5: Assumptions and Results for the Scenarios with **More and Less LNG** Compared with the Reference Case 38

Table 6: Assumptions and Results for the Scenarios with **More and Less Imports** Compared with the Reference Case 39

Table 7: Assumptions and Results for the Scenarios with **More and Less Dual-Fuel Replenishment** Compared with the Reference Case 39

Table 8: Assumptions and Results for the Scenario with **More Retirements** Compared with the Reference Case 40

Table 9: Assumptions and Results for the **Combination LNG Scenarios** Compared with the Reference Case 41

Table 10: Assumptions and Results for the **Combination Scenario with High Retirements** Compared with the Reference Case 41

Table 11: Assumptions and Results for the **Combination Scenario with Maximum Retirements and Renewables** Compared with the Reference Case 42

Table 12: Assumptions and Results for the **Pipeline Compressor Outage** Scenarios 44

Table 13: Assumptions and Results for the **Millstone Nuclear Outage** Scenarios 45

Table 14: Assumptions and Results for the **Distrigas and Mystic 8 and 9 Outage** Scenarios 46

Table 15: Assumptions and Results for the **Canaport LNG Outage** Scenarios 46

Highlights: Operational Fuel-Security Analysis

- **Fuel-security risk** – the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter – is the **foremost challenge to a reliable power grid in New England**.

- ISO New England studied **23 possible future resource combinations** during winter 2024/2025 to determine whether enough fuel would be available to meet demand and to understand the operational risks.

- The ISO chose winter 2024/2025 and 23 scenarios to depict a **wide range of possible future power system conditions** in the mid-2020s. Actual power grid conditions could change earlier or later than the 2024/2025 target winter.

- These scenarios, while not a precise prediction of the future system, seek to illustrate the **range of potential risks** that could confront a power system if fuel and energy were constrained during winter.

- The goal is to improve the ISO's and the region's **understanding of these risks** and inform the ISO's subsequent discussions with stakeholders.

- The study assumed that no additional natural gas pipeline capacity to serve generators would be added within the timeframe of this study and instead focused on **five other variables** that are likely to be key factors in power system reliability. Notable findings regarding each variable:

Resource Retirements

The retirements of coal-fired, oil-fired, and nuclear generators – resources with fuel stored on site – will have a significant impact on reliability and magnify the importance of other variables, particularly liquefied natural gas (LNG) supplies.

LNG Availability

Improving generators' advance arrangements for timely winter deliveries of LNG could significantly reduce fuel-security risk, while reduced volumes of this global commodity would raise risk.

Oil Tank Inventories

The availability of oil stored in tanks on site is a key reliability factor and depends on the extent to which natural-gas-fired generators are able to add dual-fuel capability to burn oil, how often they can run on oil, and whether they have oil when needed.

Imported Electricity

Expanding access to electricity from neighboring power systems would help mitigate fuel-security risk but would require investment in transmission infrastructure.

Renewable Resources

Accelerating the growth of renewable resources would enhance fuel security but would not eliminate reliance on LNG. It also would likely lead to more non-gas-fired resource retirements and require transmission investment.

Energy shortfalls due to inadequate fuel would occur with almost every fuel-mix scenario in winter 2024/2025, requiring frequent use of **emergency actions** to keep power flowing and protect the grid. Emergency actions that would be visible to the public range from requests for energy conservation to load shedding (rolling blackouts affecting blocks of customers).

The study's findings suggest **six major conclusions:**

1. **Outages:** The region is vulnerable to the season-long outage of any of several major energy facilities.

2. **Stored fuels:** Power system reliability is heavily dependent on LNG and electricity imports; more dual-fuel capability is also a key reliability factor, but permitting for construction and emissions is difficult.

3. **Logistics:** The timely availability of fuel is critical, highlighting the importance of fuel-delivery logistics.

4. **Risk trends:** All but four scenarios result in fuel shortages requiring load shedding, indicating the trends affecting New England's power system may intensify the region's fuel-security risk.

5. **Renewables:** More renewable resources can help lessen the region's fuel-security risk but are likely to drive coal- and oil-fired generation retirements, requiring high LNG imports to counteract the loss of stored fuels.

6. **Positive outcomes:** Higher levels of LNG, imports, and renewables can minimize system stress and maintain reliability; to attain these higher levels, delivery assurances for LNG and electricity imports, as well as transmission expansion, will be needed.

The ISO will discuss the study with regional stakeholders and determine whether further **operational or market design measures** are needed to address the region's fuel-security risk.

Executive Summary

The health and safety of New England's 14 million residents and the vibrancy of its economy depend on a reliable power supply, and that requires fuel security – that is, a reliable supply of the various fuels used to generate the region's electricity. New England's generation fleet relies primarily on fuels imported from elsewhere in the United States or from overseas to produce power, giving fuel procurement, transportation, and storage a pivotal role in power system operations. This is particularly true during winter when fuel for nearly half the region's generating capacity may become inaccessible due to priority demand for natural gas from the heating sector.

As the operator of the region's six-state power system, ISO New England is required to plan and operate the grid to ensure a reliable supply of electricity. To help fulfill this responsibility, the ISO conducted a fuel-security analysis that evaluated the level of operational risk posed to the power system by a wide range of potential fuel-mix scenarios. The study quantified the risk by calculating whether enough fuel would be available for the system to satisfy consumer electricity demand and to maintain power system reliability throughout an entire winter.

Fuel-security risk**—the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter—**is the foremost challenge to a reliable power grid in New England.

Background

On multiple occasions in recent winters, the ISO has had to manage the system with uncertainty about whether power plants could arrange for the fuel – primarily natural gas – needed to run.[1] Because the ISO has no jurisdiction over other industries' various fuel-delivery systems, it has addressed the effects of insufficient fuel supplies on the power system by employing real-time emergency operating procedures and implementing market design changes to incentivize generators to arrange for adequate fuel supplies. The ISO has also worked on improving communication and coordination with natural gas pipeline operators.

The ISO has been able to maintain power system reliability during severe winter conditions without using all its emergency procedures. However, the evolving generation mix is increasingly susceptible to variable and uncertain factors. Natural gas pipeline constraints, the logistics of importing liquefied natural gas (LNG)

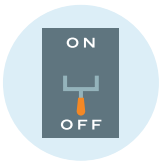
1. **Winter 2003/2004:** ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* (October 12, 2004), https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf; **Winter 2012/2013:** ISO New England, "Winter Operations Summary: January–February 2013," discussion paper (February 27, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_27_draft_for_discussion.pdf; and **Winter 2013/2014:** ISO New England, "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabilit.html.

and fuel oil, the impact of New England's weather on the availability and timing of fuel deliveries, and the amount and timing of electricity generated by renewable resources all contribute to a high level of uncertainty for ISO system operations.

In fall 2016, ISO New England initiated a study to better understand any potential future impacts of fuel-security risk. The study estimated the operational impacts of possible fuel-mix scenarios so that the ISO and the region can assess the level of risk and plan appropriate mitigation, if needed. Economic effects were not measured.

The Study

While actual power grid conditions could change earlier or later than the target winter, the ISO modeled a wide range of resource combinations that might be possible by **winter 2024/2025,** considering **five key fuel variables:**

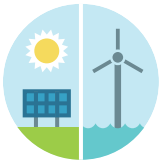


The retirements of coal- and oil-fired generators

The availability of LNG

Dual-fuel generators' oil tank inventories (i.e., how often on-site fuel tanks can be filled at dual-fuel generators that can switch between natural gas and oil)

Electricity imports



The addition of renewable resources

This study did not assess the impacts of adding natural gas pipeline capacity to serve generators within the timeframe of this study. The study incorporated the demand-reducing effects of projected energy-efficiency measures and distributed solar power.

The study includes **23 scenarios:**

- **1 reference case** incorporates likely levels of each variable if the power system continues to evolve on its current path, serving as a baseline for comparison with other scenarios.
- **8 single-variable cases** increase or decrease the level of just one key variable to assess its relative impact in each case.
- **2 boundary cases** illustrate what would happen if either all the favorable or all the unfavorable variables were realized simultaneously.
- **4 combination cases** combine the five key variables to represent future resource portfolios that could develop and their effects on fuel security.
- **8 outage cases** illustrate the effects of a winter-long outage at major energy facilities in the region.

The operational impact was measured in hours of emergency operating procedures that would be required to maintain system reliability when not enough fuel was available to generate all the electricity needed to meet forecasted electricity demand.

Key Takeaways

In almost all future resource combinations, the power system was unable to meet electricity demand and maintain reliability without some degree of emergency actions. Some key takeaways:

- **Load shedding (19 cases)** – Among the combination cases, all but the most optimistic case resulted in load shedding, also known as rolling blackouts or controlled outages that disconnect blocks of customers sequentially. Load shedding is implemented as a last resort to protect the grid. All but three of the single-variable cases resulted in some degree of load shedding.
- **Public requests for energy conservation (22 cases)** – All but one of the cases led to the use of emergency actions that include public requests for energy conservation.
- **No emergency actions (1 case)** – The favorable boundary case represented a best-case resource combination that was fully able to meet demand without special actions. However, it did not reflect the increase in retirements of oil-fired generators that would be expected to accompany increased levels of the other four variables: LNG, oil inventories for dual-fuel generators, imports, and renewables.
- **Vulnerabilities** – The single-variable cases revealed the region's vulnerability to resource retirements and the availability of LNG. These cases also show that while increasing the amount of renewables would enhance fuel security, it would not eliminate reliance on imported LNG.

The study results are not precise predictions. *Rather, they help compare different possible future fuel scenarios so that the ISO and the region can discuss a level of tolerable risk and plan appropriate mitigation.*

- **Outages** – All the outage cases resulted in many hours of load shedding, particularly the season-long loss of a nuclear plant or pipeline compressor. Even significant increases in LNG, dual-fuel capability, and renewables would not eliminate the risk. While outages of shorter duration were not studied, it's likely that an outage of any duration at any of these facilities would create significant system stress.

The results are derived from the 23 scenarios analyzed; not every possible future resource combination has been modeled in this study. The study results should not be interpreted as precise measurements. Instead, the number of hours of emergency actions for each fuel scenario should be interpreted as an indicator of system stress.

Taken together, the study results suggest that **New England could be headed for significant levels of emergency actions**, particularly during major fuel or resource outages. Harder to measure are the risks to the region from brief, high-demand cold spells, which present particular logistical challenges for fuel procurement and transportation.

Next Steps

The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018. A key question to be addressed will be the level of fuel-security risk the ISO, the region, and its policymakers and regulators would be willing to tolerate. A primary consideration for the ISO is its responsibility, as a regional reliability coordinator, to operate the New England power system in a way that maintains the reliability of the entire Eastern Interconnection.[2]

2. The Eastern Interconnection is one of two major alternating-current power grids in North America covering from central Canada east to the Atlantic coast (excluding Québec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas). During normal system conditions, all the smaller power systems in this area are electrically interconnected and operate at a synchronized frequency of 60 Hz average. The Eastern Interconnection is tied to the Western Interconnection, the Texas Interconnection, and the Québec Interconnection generally through numerous high-voltage direct-current transmission lines.

Background:

The Changing Grid and New England's Fuel-Supply, Infrastructure, and Logistical Challenges

A reliable power system requires a reliable supply of the fuels used to generate electricity. Because New England depends primarily on imported fuels to produce power, fuel security – or the assurance that power plants will have or be able to get the fuel they need, when they need it – is critical for the region's power system reliability.

Fuel security is a growing concern in New England. The regional power system is increasingly dependent on natural gas for power generation; the capacity of the region's natural gas infrastructure is not always adequate to deliver all the gas needed for both heating and power generation during winter; and natural gas is the fuel of choice for a large segment of new power plant proposals. The region's coal, oil, and nuclear power plants, which have fuel stored on site and are essential for reliability when natural gas is in short supply, are retiring. Further, the region has limited dual-fuel generating capability – that is, generators that can use either natural gas or oil – and emissions restrictions on burning oil are tightening.[3]

A dependable fuel supply requires a fuel-delivery system that has the appropriate physical capability to transport all the fuel needed, the contractual arrangements secured in advance to ensure timely deliveries, and power plants that have fuel storage on site. In New England, fuels need to be delivered and storage must be available throughout the winter months.

The region's fuel-security risks have been evident to ISO New England since a 2004 cold snap.[4] The ISO, a private, not-for-profit company independent from all companies doing business in the region's electricity marketplace, operates the six-state power grid around the clock. The ISO is responsible for maintaining the precise balance of supply and demand required to keep the lights on in New England and avoid cascading power system infrastructure outages that can trigger a widespread blackout.

On multiple occasions in recent winters, the ISO's system operators have been confronted with the challenges that arise when power plants can't get fuel. Because the reliability of New England's power system was maintained throughout these events, the region's electricity consumers have been shielded from this growing risk, apart from severe winter price spikes that eventually show up in retail rates.[5]

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3. The region's current fleet of dual-fuel capable power plants totals about 8,750 megawatts (MW), but this includes about 2,200 MW from older, oil-fired power plants that rarely run on natural gas and are at risk of retirement.

4. During a January 2004 cold snap, more than 6,000 MW of natural-gas-fired generation was unavailable, much of it due to lack of fuel. ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 'Cold Snap"* (October 12, 2004), https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf.

5. The total value of the wholesale energy market for the three months of winter 2013/2014 was about $5.05 billion. By comparison, the value of energy market transactions in 2016 – the year with the lowest wholesale power prices since 2003 – was $4.1 billion for the entire 12 months. Refer to the ISO's "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabilit.html.

The Changing Grid

These real-world challenges are likely to intensify as a result of several interconnected trends that are rapidly changing the makeup of New England's power system:

- Increasing use of natural gas generation as the region shifts away from coal- and oil-fired power plants
- Retirements of coal- and oil-fired power plants and nuclear plants
- Growth of renewable resources, propelled by state initiatives
- Growth of resources that reduce consumer demand from the regional grid: energy-efficiency (EE) measures, such as energy-saving lightbulbs, and "behind-the-meter" (BTM) solar panels installed at homes and businesses on the distribution systems managed by local utilities

The Dash to Gas

The two most significant of these trends are the increasing use of natural gas and the retirement of power plants that use fuels other than natural gas. By far the biggest factor is the "dash to gas." Two decades ago, the regional power system derived most of its electricity from generators with fuel stored on site: coal, oil, and nuclear. Today, coal-fired, oil-fired, and nuclear power plants are still a significant portion of the region's generation fleet, but natural-gas-fired generators make up nearly half the fleet and use "just-in-time" fuel deliveries.

In 2000, oil- and coal-fired power plants produced 40% of the electricity generated in New England, while natural gas produced 15%. Starting in 2009, natural gas prices plummeted with the boom in domestic shale gas production. Because ISO New England dispatches the lowest-cost resources first to meet demand, natural-gas-fired generators are used most often. By 2016, natural gas generation had risen to nearly half the electricity produced in New England (49%), while coal and oil dropped to 3% of annual electricity generation, although they still make up nearly 30% of the region's total generating capacity.

While the use of natural gas for both heating and power generation is growing, the natural gas supply infrastructure is not expanding at the same pace, resulting in natural gas supply constraints in winter.[6] Given the region's current and growing reliance on natural gas, limitations on the region's natural gas delivery infrastructure are the most significant component of New England's fuel-security risk.

When pipeline supply constraints occur, all or almost all the available natural gas goes to heating customers. When natural-gas-fired power plants haven't been able to procure the fuel they need to run during recent winters, most of the region's power has come from coal, oil, and nuclear power plants – generators with readily available fuel stored on site – and imports from neighboring power systems with adequate natural gas infrastructure or energy storage in the form of hydroelectric facilities.[7]

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6. ICF International, *New England LDC Gas Demand Forecast Through 2030*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.

7. While pumped hydroelectric facilities are considered to have "stored fuel," in this report the term applies to coal, oil, and nuclear power plants. New England has three pumped-storage hydro facilities that store energy in the form of water in large ponds; when released through turbines, this stored water can provide critical reliability support by generating more than 1,800 MW of energy within 10 minutes, and for up to seven hours. The loss of pumped storage was not studied in this analysis, but pumped storage was included in the dispatch of resources to meet demand.

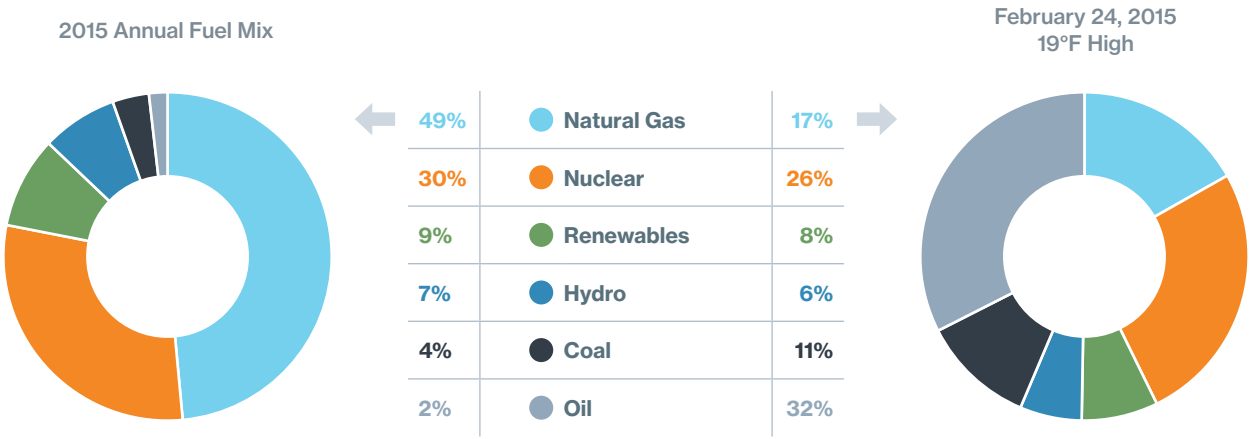
Retirements of Coal, Oil, and Nuclear Power Plants

The low average annual output from generators using oil or coal masks the major contributions of these aging generators during peak winter and summer days when they may be contributing as much as a third, sometimes more, of the region's power (see Figure 1). These are typically days when summer demand peaks or during winter when generators can't access enough natural gas or the price of natural gas spikes.

Generators with Stored Fuels Are Key Contributors to Reliability on Cold Days

During winter 2014/2015, combined contributions from oil and coal peaked at over 40% of regional generation on February 24, 2015. Annually, however, these fuels together produced only 6% of New England's generation. Nuclear power, another major non-gas-fired generation source, also made a significant contribution on February 24, 2015. Natural-gas-fired generation, meanwhile, dropped to just 17% for the day, despite providing 49% annually.

Figure 1: 2015 Annual Fuel Mix Compared with Day of Highest Coal and Oil Generation in 2015



Source: ISO New England, *2000–2015 Net Energy and Peak Load by Source* and *Daily Generation by Fuel Type 2015*

In 2012, as part of its Strategic Planning Initiative, the ISO identified about 8,300 megawatts (MW) of coal- and oil-fired generators at risk of retirement due to age and economic headwinds.[8] Between 2013 and 2019, nearly 3,000 MW of coal- and oil-fired generation have retired or will retire, leaving about 5,400 MW available but at risk of retirement.

Nuclear power plants represent about 13% of New England's generating fleet but produced 31% of the region's electricity in 2016. Nuclear plants are also retiring in New England and across the country; owners have cited low wholesale electricity prices stemming from low-priced natural gas as the key driver. Vermont Yankee retired at the end of 2014, and Pilgrim will retire by 2019, removing about 1,300 MW of baseload power from New England's fleet.

8. ISO New England, "Strategic Planning Initiative Key Project," webpage (2017), https://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative, and *Strategic Transmission Analysis: Generation at Risk of Retirement*, Planning Advisory Committee (PAC) presentation (December 18, 2012), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/retirements_redacted.pdf.

In total, the recent and impending retirements of coal-fired, oil-fired, and nuclear power plants add up to the departure by June 2021 of 4,600 MW of generators that use fuels other than natural gas.[9] That's more than 10% of the region's total installed power plant capacity.

The retirements of these aging generators may accelerate as more renewable resources are added to the regional power system. Renewable resources often have the benefit of state and federal financial incentives, as well as long-term contracts sponsored by states seeking to expand their clean energy portfolios. As such, these renewable resources have low costs and can bring down prices in both the energy and capacity markets. These lower prices may drive out coal- and oil-fired generators and nuclear plants dependent on these revenues.

Growth of Renewable Resources

New England's fleet of renewable resources, powered by water, sun, wind, biomass, and trash, is still small, but wind and solar resources are growing rapidly. The region now has 25 onshore wind farms with more than 1,200 MW of nameplate capacity, up from 375 MW just six years ago, in 2011.[10] State and federal production credits and tax incentives have encouraged this growth.

Additional onshore wind facilities face challenges in development. Most are proposed for construction in remote areas of northern New England where the transmission system was sized to serve the sparse local population, not to carry large amounts of generation. Building the transmission needed to deliver the proposed wind energy to southern New England load centers has proven to be challenging for developers and the region.

The nation's first offshore wind farm, with a 30 MW nameplate capacity, came on line in 2016 off the coast of Block Island, and several companies are competing to build much larger wind farms off the coast of Massachusetts and Rhode Island.

New England has a long history of hydroelectric generation, with hundreds of small dams and several larger facilities. Pumped storage is also a key resource in the region. New England imports about 17% of its energy annually, with much of that coming from Hydro-Québec, which gets almost all its energy from hydro facilities.

The New England states have goals and requirements for clean energy that serve as a major driver of the growth of renewable resources in the region. Massachusetts, Connecticut, and Rhode Island issued a request for clean energy proposals in 2016 and have selected proposals for 460 MW.[11] Massachusetts is also implementing legislation that calls for the equivalent of about 1,200 MW of clean energy, including hydro from Canada, by 2022.[12] The request for proposals (RFP) for this initiative drew a robust response. The legislation also calls for 1,600 MW of offshore wind by 2027.

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9. The retirements of coal- and oil-fired generators include Salem Harbor (749 MW, shut down in 2011 and 2014), Norwalk Harbor (342 MW, shut down in 2013), Brayton Point (1,535 MW, retired 2017), Mount Tom (143 MW, shut down in 2014), and Bridgeport Harbor 3 (383 MW by June 2021). The nuclear retirements include Vermont Yankee (604 MW, retired 2014) and Pilgrim (677 MW by June 2019). The 4,600 MW also includes a number of smaller generators.

10. *Nameplate* refers to the maximum electricity a resource is rated capable of providing. Most resources' actual output is a smaller percentage of maximum due to outages, and most renewable resources have a lower actual output percentage due to the variability of weather. Actual production from solar photovoltaics (PV) is expected to be about 8% of nameplate (shorter days, more cloud cover in winter), while the output from onshore wind is expected at about 48% and offshore wind at about 53% of nameplate capability.

11. *New England Clean Energy RFP* (https://cleanenergyrfp.com/). In November 2015, Massachusetts, Connecticut and Rhode Island, issued an RFP to deliver additional supplies of renewable energy and large-scale hydropower to the New England power system. The three states collectively selected projects representing about 460 MW of clean energy for the New England market. None of the projects included associated transmission to deliver the clean energy supplies to New England load centers. The selection of the winning bids will not be final until contract negotiations and regulatory approvals are complete.

12. Massachusetts Gov. Charlie Baker, "Governor Baker Signs Comprehensive Energy Diversity Legislation," press release (August 8, 2016), http://www.mass.gov/governor/press-office/press-releases/fy2017/governor-baker-signs-comprehensive-energy-diversity-law.html. In Massachusetts, *An Act to Promote Energy Diversity* (H. 4568), requires Massachusetts electricity distribution companies to procure 1,600 MW of cost-effective offshore wind energy by 2027 and about 1,200 MW of clean energy generation – baseload hydropower, onshore wind, and solar supported by hydropower, standalone onshore wind, solar, or other Class I renewable resources by 2022. (https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188)

The queue of new generation projects seeking to interconnect to the high-voltage power grid operated by the ISO totaled about 13,500 MW as of December 1, 2017. Proposed wind farms make up just over half the proposals, or about 7,300 MW. The queue also includes 1,000 MW of proposed solar (8% of the total) and 400 MW of battery storage (3% of the total). Not all these projects will be constructed; historically, about 68% of the megawatts proposed are never built.

The vast majority of solar photovoltaic (PV) resources in New England are behind the meter, on the distribution system managed by local electric power utilities. A handful of large solar farms are participating in the regional wholesale markets totaling about 50 MW (nameplate); the largest is about 16 MW.

Advanced storage technologies hold promise as resources that can support reliability and the technology is progressing, but cost-effective, advanced energy storage is not yet available at a scale that can ensure reliability on a 35,000-MW power system. Currently, there are about 20 MW of utility-scale battery storage connected to the regional grid; it is unclear at this stage how higher levels of battery storage will affect the frequency and duration of energy shortages.

Growth of Energy-Efficiency Measures and Behind-the-Meter Solar

The New England states are national leaders in energy efficiency, collectively spending more than $1 billion annually to install energy-efficiency measures in homes and businesses.[13] The efforts are paying off, according to ISO New England's annual energy-efficiency forecast.[14] Total annual energy consumption in New England is tapering off, while winter peak demand is forecasted to decline very slightly from 2017 to 2026.

Behind-the-meter solar photovoltaic installations are also fueling reductions in energy consumption and peak demand. Just five years ago, at the end of 2012, New England had about 250 MW of BTM solar PV installed. At the end of 2016, the number had increased to 1,900 MW, and the ISO's PV forecast projects that by 2024, the region will have 4,400 MW of solar PV (and 4,700 MW by 2026).[15] All this new PV will be installed at homes and businesses on the distribution system, serving to reduce demand for power from the regional power grid. State incentives, particularly in Massachusetts, are helping drive this growth.

By lowering demand from the regional grid, these resources can have the effect of lowering prices as well, diminishing energy and capacity revenues and creating greater financial pressure on more costly resources.

Logistical Uncertainties: Fuel Deliveries and Weather

The region still needs power plants with fuel stored on site, but if they can't get the fuel, they can't run. The uncertainty surrounding New England's fuel-security risk is compounded by an unquantifiable X factor: fuel-delivery logistics.

Fuel-security risks may be more acute in New England than in most other regions because New England is "at the end of the pipeline" when it comes to the fuels used most often to generate the region's power. New England has no indigenous fossil fuels and therefore, fuels must be delivered by ship, truck, pipeline, or barge from distant places.

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13. American Council for an Energy-Efficient Economy, "California Golden Again on Energy Efficiency, Regains #1-State Spot in Tie with 6-Time Winner Massachusetts," press release (September 27, 2016), http://aceee.org/press/2016/09/california-golden-again-energy.

14. ISO New England, "Final Energy Efficiency Forecast: 2021-2026" (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/final_eef_2017_v2.pdf.

15. ISO New England, "2017 Final PV Forecast" (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf.

The natural gas pipeline system within New England is relatively small, and its access to the rest of the North American pipeline network is limited. In regions with a more robust pipeline network, a failure of a single point on the pipeline system typically can be contained to a local area and routed around, but such an outage in New England will likely create significant impacts.

Limitations or constraints on the fuel-supply chain are not unusual, particularly during bad weather. Winter storms can impede deliveries from liquefied natural gas (LNG) tankers, oil barges, and oil tanker trucks. Low temperatures can increase heating demand for natural gas, oil, and LNG, leaving less for power plants.

Renewable resources can help reduce the demand for energy and the fuels that generate it, but the output of wind and solar facilities depends on the weather and time of day. For example, solar panels can reduce the consumption of natural gas and oil during sunny winter days, so more oil and gas are available later to generate electricity to meet the daily winter peak demand. Solar energy can't help directly with the winter peak, however, because demand peaks after the sun has set.

The timing of fuel consumption and of fuel replenishment can be significant as well. In December, the weather is typically milder. As winter progresses in time and intensity, generators' oil and LNG inventories are depleted and tanks must be refilled rapidly.

Some typical logistical concerns for each fuel are outlined below:

- **Natural gas**
  - **Pipeline gas**. New England receives natural gas via five pipelines from the west through New York State, and from Canada in the north.

    Most of the region's pipeline gas is delivered through New York, where natural-gas-fired generators have the first opportunity to withdraw any surplus natural gas that is not already committed to the gas utilities.[16] Developers are proposing to build more new natural-gas-fired generation in eastern New York. Indian Point Energy Center, a nearly 2,100 MW nuclear station near New York City, has announced it will retire by 2021, which may increase demand for natural gas from generators in New York and could result in reduced supply to New England generators during periods of peak demand.[17] This study does not attempt to quantify these effects, however. Further, construction of additional pipeline capacity in New York will likely prove difficult.[18] Some natural gas is delivered to New England via pipeline from eastern Canadian natural gas fields off Nova Scotia, but most of this supply will be gone by 2020. The primary sources of natural gas for the Canadian Maritimes will become Canaport, a 10 billion cubic feet (Bcf) LNG import, storage, and regasification facility in New Brunswick, and the Maritimes and Northeast (M&N) pipeline. When it is serving Maritimes heating

16. ICF International, *Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies* (November 18, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11_18_2013.pdf. Eastern Interconnection Planning Collaborative (EIPC), *Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems* (March 9, 2015), p. 149, http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

17. New York ISO, *Power Trends: New York's Evolving Electric Grid*, *2017* (2017), p. 35, https://www.google.com/url?q=http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf&sa=U&ved=0ahUKEwicr-KkrO7VAhWCwFQKHSc1C1QQFggEMAA&client=internal-uds-cse&usg=AFQjCNG4pCnCu_ZyHocx1sQurUb0HzeJ5A. Patrick McGeehan, "Cuomo Confirms Deal to Close Indian Point Nuclear Plant" (New York Times [NYT], January 9, 2017), https://www.nytimes.com/2017/01/09/nyregion/cuomo-indian-point-nuclear-plant.html.

18. New York ISO, *Power Trends, 2017*, pp. 36–37.

demand, the M&N will be transporting gas from New York or Québec, through New England, to the Maritimes. The result could be less pipeline gas for New England.[19]

- **Liquefied natural gas.** LNG can be an important complement to pipeline gas. It is imported to New England from overseas by ocean-going tankers, typically from Trinidad and Tobago. Most cargoes of LNG need to be contracted and scheduled for months before winter begins; once contracted, the LNG won't arrive for at least five days.

  LNG availability can also be affected by global weather or political events.[20] Ocean-going tankers can have difficulty offloading their cargoes at offshore LNG buoys or in ports during winter storms. Cold snaps can result in a sudden drawdown of stored LNG, and the rapid depletion of LNG combined with the region's limited storage facilities can challenge the region's fuel-supply chain, particularly if outages increase the need for LNG.

- **Oil.** The region's remaining oil-fired power plants get their fuel delivered by oil pipeline, barges, or tanker trucks – but as more and more oil-fired power plants have retired, the delivery supply chain has withered as well. Fewer oil barges and tanker trucks are located in New England. Oil-fired generators may start the winter with full tanks of oil stored on site, but a generator that depletes its oil inventory during a cold snap may not be able to refill its tank promptly if a winter storm prevents tanker trucks from traveling.

  In winter, oil delivery trucks may be occupied delivering fuel to heating oil dealers and unavailable for power plant deliveries, or federal restrictions on how many hours drivers can drive may delay deliveries. Rivers may freeze, preventing barges from bringing fuel to generators.

  In addition to potential fuel-delivery concerns, environmental restrictions limit how often many power plants can generate electricity using oil. Many of the region's dual-fuel power plants are currently limited to running no more than approximately 30 days per year on oil, and Massachusetts is implementing tighter air emissions regulations.

Natural Gas Delivery Challenges: Infrastructure Constraints and Contracts

The natural gas system was sized and built to meet the peak demand needs of the local natural gas utilities (also called local distribution companies, or LDCs) serving heating customers. The natural gas utilities contracted for the pipeline capacity, so they have first priority for gas delivery.

On many days, pipeline capacity is sufficient for both the local gas utilities and the natural-gas-fired power plants, but during the coldest weeks of the year, this natural gas delivery infrastructure can't meet all the demand for natural gas for both home heating and power generation. As a result, natural-gas-fired power plants – which typically buy pipeline capacity released by local gas utilities on the secondary market – may not be able to access natural gas.

19. "Nova Scotia's Deep Panuke natural gas projects drying up" (*The Chronicle Herald*, May 30, 2017), http://thechronicleherald.ca/business/1473337-nova-scotias-deep-panuke-natural-gas-projects-drying-up.

20. Erin Ailworth, "Unrest in Yemen may result in local LNG shortage" (*Boston Globe*, May 5, 2012), http://www.bostonglobe.com/business/2012/05/04/electric-power-plants-threatened-attacks-gas-pipelines-yemen/48P2O2KqNm9sEa2P6dr6lM/story.html.

Contracting with pipelines for some level of firm natural gas delivery could solve this problem if the pipeline system expanded to accommodate the increased contracted demand. However, contracting for firm pipeline capacity is costly and requires a long-term commitment. This has been a deterrent for natural gas power plant owners, who have short- to medium-term financial horizons and are a diverse group with diverse market interests.

Contracting for LNG could also help if these contracts are executed before winter arrives. Typically, the ocean-going tankers that transport LNG are committed in the fall for winter delivery, so a sudden or unanticipated need to replenish LNG supplies may go unmet during an unexpectedly bad winter. In addition, as heating demand for natural gas grows, local gas utilities are likely to begin contracting for more of the region's limited LNG storage capacity, leaving even less for natural-gas-fired power plants.

Further, contracting for oil and LNG deliveries can be difficult during winter when other types of customers (e.g., heating, industrial customers) are also seeking urgent deliveries. When power plants don't sign contracts for pipeline gas or LNG, nor enter the winter with full oil tanks, deliveries of oil or LNG when needed cannot be guaranteed.

The retirements of power plants with stored fuel, tightening emissions restrictions, and the reliance on a fuel that may not be available when needed most are all challenging New England's power system. Logistical and time- and weather-dependent fuel-delivery uncertainties introduce additional potential for fuel-security risks that could degrade the reliability of the regional power system.

Operational Fuel-Security Analysis

The shift away from generators with on-site fuel to natural-gas-fired generators relying on "just-in-time" fuel delivery has exposed the limitations of New England's existing fuel infrastructure and has heightened the region's fuel-security risks.

As the system continues to change, it is incumbent on ISO New England, as the reliability coordinator for New England's six-state power grid, to assess the potential operational impacts these risks may pose in the near future.[21]

Study Description

The ISO launched this operational analysis to quantify the region's future fuel-security risk – that there may be times when sufficient fuel is not available for power plants to generate all the electricity required to meet consumer demand and maintain power system reliability during the entire winter of 2024/2025.

The study determined whether or how often the region would run short of natural gas and oil during an entire 90-day winter and calculated how often the resulting energy shortfalls would require the ISO to employ emergency actions, up to and including rolling blackouts.

Resources and Key Variables

The study developed a wide range of hypothetical scenarios of a regional power system composed of different resource combinations, incorporating the same types of resources and fuels as those in New England's fleet today:

- Natural-gas-fired generators
- Oil-fired generators
- Dual-fuel generation (power plants that can use natural gas or oil stored on site; most use natural gas as their primary fuel and oil as their backup fuel)
- Renewable resources, including on- and offshore wind, solar, biomass, and behind-the-meter solar photovoltaics
- Energy-efficiency measures
- Nuclear power plants
- Hydro generation
- Pumped-storage generation
- Imports

21. North American Electric Reliability Corp, "Reliability Coordinators," webpage (2016), http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.

The exception was the region's remaining coal-fired power plants, which were assumed to be retired by 2024.

Five key factors affecting power system operations were the variables in each scenario:

- **Retirements** of generators that use fuels other than natural gas (coal and oil)
- **Imports** of electricity over transmission lines from neighboring power systems in New York and Canada
- Level of **renewable resources** on the system
- Level of **LNG injections** into the region's natural gas delivery and storage infrastructure
- **Dual-fuel generators' oil tank inventories** – that is, how often the oil tanks on site at dual-fuel power plants are filled and refilled throughout a 90-day winter

The analysis modeled 23 possible future resource-mix combinations, including four high-impact outages of key energy facilities, during December, January, and February, of winter 2024/2025.[22] The study assessed each scenario's physical capabilities to meet demand and required reserve levels by calculating the amount of fuel needed to generate all the electricity required. The study then compared the amount of fuel needed with the actual level of fuel – wind, sun, hydro, other renewables, nuclear, imported electricity, natural gas delivered via pipeline, and oil and LNG stored in tanks – the region's fuel infrastructure could deliver to each hypothetical resource mix.

The Need for Emergency Actions

The study determined whether or how often the region would run short of fuel and calculated how often the resulting energy shortfalls would require emergency actions, up to and including rolling blackouts. For each scenario with insufficient fuel to generate all the electricity needed to meet demand, the study model dispatched the resources providing reserves. If demand still existed after the reserves were depleted, the study calculated the frequency, magnitude, and duration of emergency operating procedures needed to maintain system balance.

The need to implement any emergency operating procedure is an indicator of system stress. System operators must take these actions to protect the region's high-voltage power system. The actions range from smaller steps invisible to the public up to load shedding (rolling blackouts). Load shedding would be implemented as a last resort to avoid an imbalance of supply and demand that could lead to cascading, uncontrolled outages and significant damage to the region's power grid that could spread to other regions.

Caveats

This is a unique study in that it highlights the vital role of fuel security in power system operations. It differs from previous studies in three key ways:

- **First**, it quantifies operational risk by measuring energy shortfalls and levels of system stress.
- **Second**, it focused on the availability of energy over the course of an entire winter – 90 days during December, January, and February, rather than looking at capacity availability on just one winter peak day.
- **Third**, it is not an economic study that considers fuel costs or prices.

22. The study analyzed a wide range of scenarios but did not model every possible future resource combination.

Furthermore, this analysis did not examine the impacts of additional natural gas pipeline capacity on a winter peak day when most or all the pipeline capacity will be used to serve heating customers, not power plants. This study assumed that only four incremental pipeline capacity expansions, already underway or in advanced planning as of summer 2017, would be in service by 2024/2025.[23] This additional capacity is designated for local gas utilities that contracted for the expansion in expectation of growth in demand for natural gas for heating.

This *Operational Fuel-Security Analysis* differs from the economic studies conducted by the ISO at the request of stakeholders. The economic studies consider the wholesale electricity costs that could result from various resource mixes and their fuel costs. The model in this fuel-security analysis does not directly consider fuel costs as a factor in meeting regional demand each day. An unrelated economic study the ISO conducted recently for the New England Power Pool (NEPOOL) should not be confused with this fuel-security analysis.[24] This analysis also differs from the ISO's planning studies in that it focuses on operational impacts and does not evaluate potential solutions.

While this study doesn't directly consider fuel costs or prices, it does assume that the electricity and fuel markets send price signals sufficient to make full use of the existing electricity and fuel infrastructure as needed. For example, New England electricity prices would be high enough on a given day to attract sufficient imports from neighboring areas to meet New England's needs. Further, the Forward Capacity Market's pay-for-performance requirements, which are designed to provide incentives for resources to perform when needed, are scheduled to be phased in starting June 1, 2018, but the impacts, and the timing of the impacts, are uncertain.

The future hypothetical resource combinations envisioned in each scenario may never materialize, while some may come closer to the future power system than others. Further, power system conditions seldom behave in as orderly a fashion as a study model. Conditions can vary tremendously every day, and even every hour, on a large power grid.

Imports may surge or lag, the output of renewables may be more or less than the average output used in the study, and multiple generators can trip off line on the same day.[25] Fuel replenishment may be easier or more difficult depending on winter conditions, the LNG market may be affected by global conditions that hinder or expedite deliveries, and natural gas delivered via pipeline may or may not be available in sufficient quantities. Higher energy market prices could convince some older generators not to retire, sooner-than-expected advances in technology could change and improve how the system operates, or a combination of some of these factors could alter the future power system.

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23. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf. Assumed the following additions: Algonquin Incremental Market (AIM) expansion, 0.345 Bcf/d pipeline capacity, in service January 2017; Atlantic Bridge, 0.13 Bcf/d, planned in service 2017; Connecticut Expansion, 0.07 Bcf/d, planned in service 2017; Continent-to-Coast, 0.11 Bcf/d, planned in service 2017.

24. The *2016 Economic Study Results: Peak-Gas-Day/Hour Capacity and Energy Analysis* (August 1, 2017) (https://www.iso-ne.com/static-assets/documents/2017/08/a3_2016_economic_study_natural_gas_capacity_and_energy_analysis_rev1.pdf) was a continuation of the *2016 Economic Study: NEPOOL Scenario Analysis* (July 24, 2017) (https://www.iso-ne.com/static-assets/documents/2017/07/draft_2016_phase1_nepool_scenario_analysis_report.docx). The ISO conducts economic studies at the request of stakeholders as part of the regional system planning process. The NEPOOL natural gas study evaluated the natural gas system's ability to meet the requirements of natural-gas-fired generation in the stakeholder-designed scenarios used in the *2016 NEPOOL Scenario Analysis*. The NEPOOL study assumed that the natural gas system will have no planned or forced outages and the gas delivery system will be at full capacity on the summer and winter peak days in 2025 and 2030, while this *Operational Fuel-Security Analysis* quantifies the risks associated with insufficient fuel during the 90-day winter period. The NEPOOL analysis also differs from this fuel-security analysis in terms of metrics, scenarios, and the variability in power system inputs.

25. On August 11, 2016, during a hot and humid spell that pushed up demand, a large generator tripped off line followed by several more. In all, nearly 4,300 MW of resources dropped off line unexpectedly over the course of the day. System operators implemented the first two actions of Operating Procedure No. 4 (OP 4), which allowed the system to operate with less than the required level of 30-minute reserves and to dispatch demand-response resources that curtailed their energy consumption. (http://isonewswire.com/updates/2016/10/19/summer-2016-recap-uneventful-until-august.html)

Some New England states are pursuing significant, economy-wide reductions in carbon emissions by 2050. While these efforts can be expected to put upward pressure on demand for electricity as the transportation and heating sectors turn away from fossil fuels, the pace and future effects of these policies on the power system are still unclear.

While the study calculated the number of hours of emergency actions each scenario would require as an indicator of system stress, the resulting numbers should not be construed as a precise prediction. Rather, the results provide a basis for comparing the fuel-security risk of each of the hypothetical resource combinations, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories at dual-fuel generators, imports, and renewable resources. Some resource combinations would result in more hours of emergency actions, while others would require fewer actions or none.

Electricity Demand in Winter 2014/2015 and Winter 2024/2025

The study evaluated each scenario's fuel-security risk throughout the 90-day winter of 2024/2025 based on the levels of consumer demand experienced in December, January, and February of winter 2014/2015.

Winter 2014/2015 serves as the baseline because, while it did not have the coldest days recorded in the past 10 years, it had the most sustained cold as measured by heating-degree days (HDDs).[26] Thus, it provided a wider perspective on the cumulative use of oil and LNG inventories over a full 90 days and the need to replenish these inventories as cold weather persists. If the region experienced colder winters than 2014/2015, as is possible (four winters in the past 38 years were colder, as measured by HDDs), the number and duration of energy shortfalls found in this study would be magnified. A winter with this level of sustained cold has a probability of occurring approximately once every 8 years.

ISO New England is responsible for the reliability of New England's power system under all types of system and weather conditions. No one knows before winter begins how extreme the weather will be. The ISO, the owners of generators and other equipment on the New England power system, and the fuel-supply chains that generators depend on must be prepared for a long, cold winter – perhaps as cold as 2014/2015, or even as cold as one of the winters with more heating-degree days than 2014/2015.[27] While the weather plays a primary role in operating conditions, so do other key variables, as highlighted in this study.

The hourly demand levels from winter 2014/2015 were adjusted to reflect the ISO's forecast for slightly higher net peak demand in extreme winter conditions in 2024/2025.[28] All the scenarios incorporate the ISO's latest forecasts for the effects of energy efficiency and distributed PV generation, which reduce the amount of electricity needed from the larger regional grid.

26. A degree day is a measure of heating or cooling and an indication of a building's demand for energy (fuel consumption). A zero-degree day occurs when no heating or cooling is required. As temperatures drop, more heating days are recorded; when temperatures rise, more cooling days are recorded. The base point for measuring degree days is 65 degrees Fahrenheit (˚F). Each degree of a day's mean temperature above 65˚F is counted as one cooling-degree day, while each degree of a day's mean temperature below 65˚F is counted as one heating-degree day. A day's mean temperature of 90˚F equals 25 cooling-degree days, while a day's mean temperature of 45˚F equals 20 heating-degree days.

27. Number of HDDs for 2014/2015: 3,551. Coldest winters as measured by HDDs: 1993/1994: 3,678; 2002/2003: 3,611; 1980/1981: 3,573; 1981/1982: 3,568.

28. ISO New England, *2017–2026 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT) (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls.

While actual power grid conditions could change earlier or later than the target year, the study used winter 2024/2025 as the target for several reasons. By winter 2024/2025, the outlook for power system reliability is uncertain. Given the pace of power system transformation and increasing economic pressures on the remaining oil, coal, and nuclear power plants, more retirements are expected in the next decade. The years until winter 2024 give the region time to address these challenges but don't provide any buffer to defer decisions about the region's fuel-security risk.

Overview of the Scenarios

The study's reference case incorporated each of the five key variables at levels that can reasonably be expected to materialize in New England given current trends. Several "combination" scenarios also represent a range of resource and fuel types that could realistically be expected to be available in the 2024/2025 timeframe. The reference case provides a baseline for all the other scenarios, which included differing levels of the five variables.

Eight scenarios adjusted just one of the five variables at a time, up or down from the reference case level, to assess the relative impact of each variable. For example, two scenarios were developed to show the effects of differing LNG levels. Four variables – retirements, electricity imports, renewables, and dual-fuel oil inventories – were held constant, and in one scenario, LNG injections were *increased* above the reference case level, and in the other scenario, they were *decreased* below the reference case. Retirements and renewables were exceptions – neither was adjusted down from the reference case level. And for retirements, a higher level represented a greater loss of resources and is considered less favorable, while with all other variables, a higher level is considered positive or favorable.

Two scenarios represented the most and least favorable levels of each variable to show the best- and worst-case outcomes. For the best-case scenario, all five variables were modeled at levels that would minimize fuel-security risk, including low retirements. For the worst-case scenario, all five variables were modeled at less-favorable levels that would raise fuel-security risk, including greater retirements.

The four "combination" scenarios adjusted more than one variable to represent a blend of outcomes, including cases with less LNG, more LNG, higher retirements of non-gas-fired generators, and retirements of all at-risk non-gas-fired power plants coupled with very high levels of renewables and imports.

Eight high-impact scenarios assessed the effects of an outage of four major energy facilities for the entire winter on the reliability of the power system. The impacts were assessed on a system represented by the reference case and also by the combination case with the highest levels of retirements and renewables. The outages of the following key energy facilities were studied:

- A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel to generators with a combined capacity of about 7,000 MW
- The loss of Millstone Nuclear Power Station in Connecticut, one of the region's remaining two nuclear facilities, eliminating 2,100 MW of baseload power
- The loss of the Canaport LNG import and regasification facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d of gas that could be injected into the New England and Maritimes pipeline systems

- A disruption to the Distrigas LNG import, storage, and regasification facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW gas-fired Mystic 8 and 9 generators and as much as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d)

Key Resource Assumptions

Several key assumptions about New England's future energy landscape are common to all the scenarios.

Natural Gas Supplies

On the basis of a study ICF International conducted for the ISO on probable natural gas infrastructure expansions in the region, this fuel-security analysis assumed that the region's natural gas supply infrastructure will have been expanded only incrementally beyond its current capability by 2024, including a recently completed pipeline expansion and three smaller expansions underway.[29] The ICF study found that these four planned or recently completed expansions will total 0.65 Bcf by 2018, increasing New England's pipeline capacity from 4.04 Bcf/d to 4.69 Bcf/d over the five pipelines bringing natural gas into New England from New York and Canada.

The pipeline expansions are sized to meet the future capacity requirements of the natural gas utilities that contracted for the added capacity; pipelines aren't built speculatively to accommodate potential future customers, such as natural gas generators. As such, any incremental pipeline capacity is expected to be used by natural gas utilities to serve their growing customer base.

Two natural gas fields off the coast of Nova Scotia – Sable Island and Deep Panuke – are expected to be depleted before 2025. This fuel-security study assumed that the depletion of these gas fields would leave the Canadian Maritimes with just two sources of natural gas: Canaport and the Maritimes and Northeast pipeline that carries gas between Canada and Maine.

The study assumes that by 2024/2025, on most days, some natural gas will flow via pipelines from New York or Québec, through New England via the M&N pipeline, to the Maritimes to serve heating customers.[30] Pipeline gas will be used more often than Canaport's LNG because natural gas is typically cheaper than LNG. On high-demand days when pipeline gas is insufficient, higher-priced LNG from Canaport or other sources will be needed to augment the pipeline gas supply. Under these conditions, the M&N pipeline will function as an internal distribution system carrying gas from the west to Canada, rather than as a separate source of gas from Canada to New England. Considering this shift, the study treated the M&N pipeline's 0.833 Bcf/d capacity as an internal regional pipeline rather than as a source of natural gas from outside New England.

As a result, the pipeline infrastructure capable of delivering natural gas into the region in 2024/2025 would stand at 3.86 Bcf/d over four pipelines from New York and Québec: Algonquin Gas Transmission (1.9 Bcf/d from New York), Tennessee Gas Pipeline (1.4 Bcf/d from New York), Iroquois Gas Transmission System (0.26 Bcf/d from New York), and Portland Natural Gas Transmission (0.3 Bcf/d from Québec).

The study assumed that LNG will be imported to three sources in 2024/2025: Canaport, Distrigas, and the Northeast Gateway Deepwater Port buoy off Gloucester, MA.

29. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf (Natural Gas Infrastructure Forecast).

30. The study did not factor in demand for natural gas to serve power plants in the Maritimes.

The maximum injection capability from each of the LNG facilities is 1.2 Bcf/d from Canaport, 0.4 Bcf/d from the Northeast Gateway buoy, and a maximum injection of 0.435 Bcf/d into the interstate pipeline system and the local gas utility system from the Distrigas facility. The maximum LNG that can be injected into the Canadian Maritimes and New England interstate natural gas pipeline systems is 2.04 Bcf/d.[31]

Combined, the expected pipeline capacity of 3.86 Bcf/d, plus the 2.04 Bcf/d maximum LNG that could be regasified and injected into the pipeline systems serving New England and the Maritimes, totals about 5.9 Bcf/d.

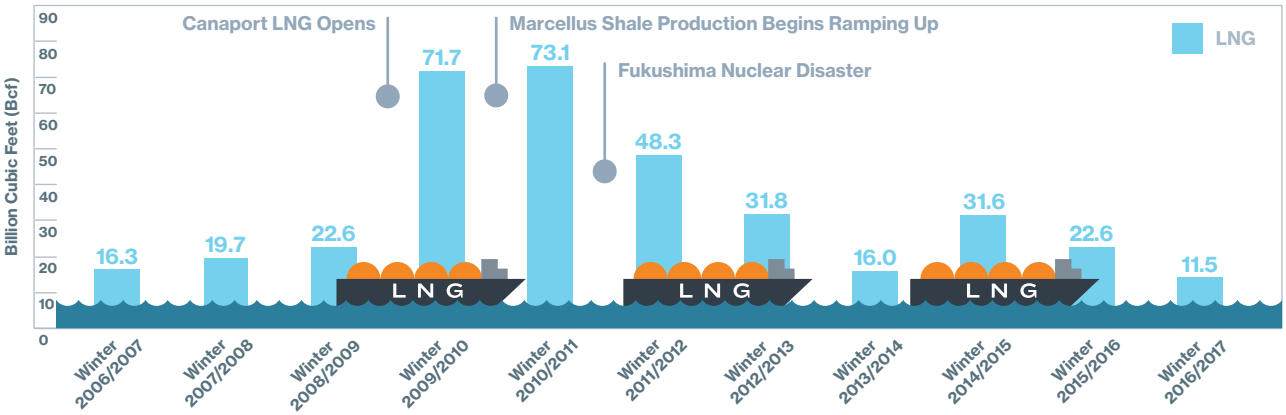
Natural gas deliveries from LNG facilities to New England pipelines have varied over the past 15 years, from none on one day in December 2016 to the maximum delivery observed at any one time of 1.25 Bcf on one day in February 2016.[32] The maximum amount of regasified LNG injected into the region's pipeline system in any scenario in this study was 1.5 Bcf/d, and the least was 0.65 Bcf/d in a scenario with an outage at Canaport.

Tracking LNG scheduled deliveries to the region's pipelines over an entire, 90-day winter season, the lowest level of LNG deliveries in the past 11 years arrived during the mild winter of 2016/2017, at 11.5 Bcf. The highest was 73.1 Bcf in winter 2010/2011, with the second-highest in 2009/2010, at 71.7 Bcf. The region's imports of LNG during winters going back to 2006/2007 are illustrated in Figure 2.

LNG Deliveries to New England Hinge on a Global Market and Winter Weather Predictions

Regional LNG deliveries vary from winter to winter for a variety of reasons, including the level of firm contracts as well as global LNG futures prices. Forecasts for a severe winter can also cause futures prices to increase. When New England's forward prices are high, destination-flexible LNG spot cargoes are likely to be attracted to the region. The primary driver for the significant increase in LNG deliveries in the winters of 2009/2010 and 2010/2011 was the new Canaport LNG import terminal in New Brunswick. Rising Marcellus shale gas production, starting in the 2010 timeframe, has lowered natural gas prices for most of the year, making LNG less competitive on price, on average. The Fukushima nuclear plant meltdown in 2011 caused a significant increase in Japan's use of LNG.

Figure 2: Winter LNG Deliveries to New England Interstate Pipelines



Note: Graph does not include the Mystic 8 and 9 gas-fired generators' fuel supply from the LNG facility.

Source: Data from NatGas Analyst Tool by Genscape, a part of DMG Information (DMGI), www.genscape.com, based on scheduled deliveries posted to gas-industry bulletin boards

Natural Gas Demand

A key factor in this study is how much natural gas will be left over for power generators after natural gas distribution companies have served their heating customers. A second study conducted in 2016 by ICF International for the ISO projected how much natural gas the gas utility companies will need in

31. The Distrigas LNG injection capacity does not count any LNG that goes directly to supply the Mystic 8 and 9 generators because this LNG is not available for injection into the interstate or local distribution pipeline systems and is not available to other generators. Likewise, the LNG used to supply Mystic 8 and 9 is not counted under the LNG caps modeled in the study scenarios.

32. This excludes any LNG directed to Mystic 8 and 9.

2024/2025.[33] This ICF study found that in winter 2014/2015, natural gas demand for heating totaled 4.4 Bcf on the winter peak day. The study also forecasted that on the coldest winter day, peak demand from local gas utilities alone could reach 5.45 Bcf/d by 2025.

Total demand for the entire year from gas utilities was 515 Bcf in 2014. The ICF study concluded that the annual demand for natural gas from local gas utilities will rise at an average of just under 2% per year, up to 591 Bcf per year in 2025 and 620 Bcf per year in 2030. As local gas utilities continue converting customers to natural gas heating, this demand will put additional pressure on gas availability for electric generation.

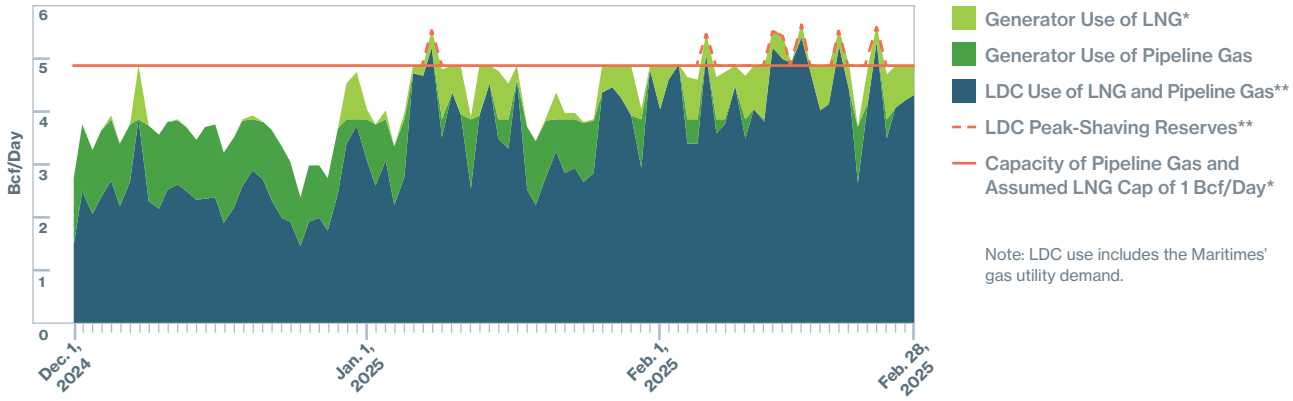
While Canada is moving to retire all its coal- and oil-fired power plants by 2030, this study does not attempt to project or include the potential impacts of additional gas demand from the electric generation sector in the Canadian Maritimes on New England's fuel security. The Maritimes' gas utility demand was included because, by 2024/2025, its heating demand is likely to be served entirely by Canaport or by importing natural gas through New England via the M&N pipeline. Either way would result in less natural gas for New England.

Figure 3 shows the effect of heating demand by local gas utilities in New England and the Maritimes on the availability of natural gas for generators, from both pipelines and from LNG.

Natural Gas Availability for Power Plants Is a Function of Heating Demand for Natural Gas

The growing use of natural gas to meet heating needs on the coldest days in New England and the Canadian Maritimes can limit the availability of natural gas, from both pipelines and LNG facilities, for New England's power plants. Local gas distribution companies (LDCs) have priority contracts with natural gas pipelines to acquire gas for their heating customers. As shown here, on some days during winter 2024/2025, the generators' need for fuel is projected to reach or exceed the region's total amount of pipeline capacity plus the assumed maximum LNG injection of up to 1 Bcf/d in the reference case. Fully meeting electricity demand on these days will hinge on the fuel inventories of non-gas-fired power resources, particularly oil (as illustrated in Figure 5 on page 36). On days when LDC demand stresses the natural gas infrastructure capacity, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities. The regulated LDCs have purchased the LNG stored in these tanks, which cannot be sold to power plants or other parties. While these reserves aren't directly available to generators, they may sometimes make more natural gas available during the operating day.

Figure 3: Winter 2024/2025 Supply of Pipeline Gas and LNG Compared to Use
(Reference Case)



*Graph does not include the Mystic 8 and 9 gas-fired generators' fuel use or supply from the LNG facility.

**Per data from ICF International, *New England LDC Gas Demand Forecast Through 2030* (December 14, 2016, presentation to Planning Advisory Committee) and *The Future of Natural Gas Supply for Nova Scotia* (March 28, 2013, for Nova Scotia Department of Energy).

33. ICF International, *New England LDC Gas Demand Forecast Through 2030*, PAC presentation (December 14, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.

Coal-Fired Generation

The study assumed that New England would have no more coal-fired power plants in winter 2024/2025.

Renewables

For each scenario, the study assumed the region would have at least 6,600 MW (nameplate capacity) of renewable resources in winter 2024/2025. This reflects the region's current amounts of wind (1,200 MW of onshore wind, 30 MW offshore) and other existing renewables, such as biomass, refuse, and solar resources (960 MW), plus all the behind-the-meter solar PV forecasted to be installed by 2024.

These assumptions were developed by studying proposed projects, as well as initiatives by the New England states. For example, the ISO's 2017 PV Forecast anticipates the region will have 4,430 MW of installed nameplate PV capacity through 2024.[34] The ISO Interconnection Queue currently includes proposals for about 4,600 MW of onshore wind and about 2,700 MW of offshore wind (as of August 15, 2017).[35] However, historically, about 68% of proposed megawatts are never constructed.

The model also incorporated into all scenarios the ISO's forecasts for growth of energy-efficiency measures. The ISO's forecast estimates that passive EE measures will lower peak demand by 3,907 MW in winter 2024/2025, to 20,761 MW in extreme winter weather. Winter peak demand is expected to decline about 0.7% per year over the 10-year planning period.[36]

Some scenarios assumed higher levels of offshore wind and behind-the-meter solar because these resources appear to have the greatest growth potential, driven by state policies and incentive programs. Onshore wind was held at the current level throughout the study timeline, given the transmission expansion that would be required to develop more onshore wind farms. However, these assumptions are not prescriptive; the megawatts modeled for one type of renewable resource in some scenarios could also be coming from other types of renewable resources, or even EE measures.

Several scenarios raised the level of renewables from 6,600 MW to 8,000 MW by adding nearly 1,400 MW of offshore wind by 2024. The cases with 8,000 MW of renewables also raised imports by 1,000 MW, to 3,500 MW, reflecting the assumption that an additional, hypothetical transmission line will be built by 2024 to address state goals for clean energy from Canada or New York.

One combination case raised renewables to 9,500 MW, the highest level of renewable resources assumed in this study. This scenario assumed that the region will have 2,000 MW of offshore wind by 2024, and that behind-the-meter solar PV will grow at a faster pace than currently projected, adding 900 MW of PV to the current forecast of 4,430 MW, for a total of 5,330 MW of BTM PV.

The cases with 9,500 MW of renewables also assumed imports of clean energy will grow by 1,000 MW as the result of higher imports over the new, hypothetical transmission tie. Adding the renewables and the 1,000 MW of additional imports brings the total clean energy assumed in this scenario to 10,500 MW (nameplate), or nearly a third of the region's current generating capacity.

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34. ISO New England, *Final 2017 PV Forecast*, presentation (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf.

35. ISO New England, "Interconnection Request Queue," webpage (August 2017), https://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

36. ISO New England, *2017–2026 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT) (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls.

Table 1 shows the assumptions for the renewables included in the reference case, the scenario with more offshore wind and imported clean energy, and the scenario with the highest level of renewables.

Table 1: Renewable Resource Assumptions

Case Scenario	Renewables Total MW (rounded)	Breakdown MW			
		Onshore Wind	Offshore Wind	PV	Other Renewables
2017	4,600	1,200	30	2,400	960
Reference Case	6,600	1,200	30	4,430	960
More Renewables	8,000	1,200	1,400	4,430	960
Max Renewables	9,500	1,200	2,000	5,330	960

Imports

Thirteen high-voltage transmission lines connect New England to neighboring power grids in New York and Québec and New Brunswick, Canada. Most of the time, New England is importing power over these lines from its neighbors.

Some of the New England states' goals that call for more clean energy, including from Canada and New York, are incorporated into some scenarios that increased imports above the 2,500 MW reference-case level. These additional imports, at 500 MW and 1,000 MW, raised total imports to 3,000 in one scenario and 3,500 in several other scenarios. The additional energy was assumed to be composed of clean energy over a hypothetical new transmission line from Canada or New York. Most of those imports would likely be coming from Québec most of the time.[37]

New England and its neighbors experience winter weather at the same time and, in fact, the demand for power in Québec and New Brunswick peaks in winter. As a result, their imports to New England could be limited as they serve their own populations. This study does not attempt to quantify these effects, however.

37. The study also assumed that New England would receive 500 MW of emergency imports from its neighbors during times of system stress when Operating Procedure No. 4 was implemented.

Methodology

The study modeled each scenario's future fuel-security risk in several steps, including:

- Calculating the amount of electricity required to meet demand each hour of a 90-day winter, from December 1, 2024, through February 28, 2025
- Calculating how much natural gas would be available after all heating demand were served, as well as the levels of oil stored on site at oil-fired and dual-fuel power plants
- Calculating how much electric energy could be generated by each fuel type
- Comparing the amount of fuel required with the level of fuel the region's fuel-delivery system could supply in each hypothetical scenario
- Assessing the magnitude and duration of emergency actions required, up to and including rolling blackouts after all operating reserves were depleted, if the fuels available were not sufficient to meet demand

The study model was based on winter conditions when oil and gas fuels were expected to be tight, so demand was met by dispatching non-oil-fired and non-natural-gas-fired generators first. Resources in this category included renewables, such as on- and offshore wind, solar PV, other renewables (e.g., biomass, refuse, landfill gas); nuclear; and hydro, including pumped storage. Next in the dispatch order were imports, then natural-gas-fired generators. If all power plants were already operating at full capability, and more demand for power still needed to be served, dual-fuel generators with stored oil would be dispatched. Finally, oil-only generators would be used.

If not enough stored oil and LNG were available to generate all the power needed to meet the remaining demand, the study calculated the frequency, magnitude, and duration of the emergency actions needed to maintain system balance and meet reliability requirements.

Metrics: How System Stress Was Measured

The study quantified how often energy shortfalls – that is, insufficient fuel to generate all the electricity needed – would occur that would require the ISO to use special procedures to serve consumer demand while maintaining the required level of reserves.

These operating procedures include tools used commonly by the ISO to manage imbalances in supply and demand, as well as emergency actions in more serious conditions. These procedures currently include allowing 30-minute reserves to be depleted, calling on demand-response resources to reduce energy usage, arranging for emergency purchases from neighboring systems, as well as tools used infrequently, such as voltage reductions (also known as brownouts). When deploying these emergency procedures, the ISO can call for the action that will best address the situation at hand; no specific order of implementation is required. If necessary, in an extreme emergency, the ISO can also skip these procedures and implement load shedding immediately.

As system stress intensified in each scenario, the study model progressed through a series of operating procedures, from those that have no impact on electricity service to consumers; to procedures that have minor public impacts, including requests for voluntary conservation and voltage reductions; and then to the depletion of 10-minute operating reserves before finally resorting to load shedding.

Ten-minute reserves are resources that can come on line within 10 minutes to cover for the unexpected loss of a resource. The depletion of 10-minute operating reserves is a significant step – once these reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding. This would be necessary to operate the system reliably and comply with mandatory national standards to avoid uncontrolled outages that could cascade across New England and threaten the entire interconnected system of power grids from the Atlantic Ocean to the Rocky Mountains.

Required Reserve Levels

ISO New England is required to carry operating reserves to respond to the unexpected loss of any resource on the power system, such as when a large generator trips off line, and almost all the procedures employed in this analysis are used to maintain the required level of reserves. Reserves are insurance – the power plants providing reserves are ready to respond quickly to replace the lost electricity and recover system equilibrium, so that no one loses power and cascading outages are avoided. The North American Electric Reliability Corp., the Northeast Power Coordinating Council, and ISO New England all have requirements for maintaining reserve levels.[38] Beyond the operational risks involved in having insufficient reserves, not meeting these reserve requirements carries consequences, including fines.

The ISO maintains 10-minute operating reserves sufficient to recover from the loss of the largest source of power, whether it's a large generator or transmission line importing power. That's normally between 1,560 MW and 2,250 MW. Thirty-minute reserves – generators that can come on line within 30 minutes – are also required to help the system replenish the 10-minute reserves. Thirty-minute reserves are equivalent to 50% of the second-largest source of supply, which is normally about 625 MW. The depletion of 30-minute reserves typically is the first action taken when the ISO declares Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*.[39] The study assumed 2,300 MW of reserves.

Operating Procedure No. 4

Operating Procedure No. 4 is the procedure used most often by ISO New England to maintain supply and demand in balance, to avoid violating the 10-minute operating reserve requirement, and to avert the need to implement load shedding. OP 4 includes 11 actions (see Table 2). Most OP 4 actions require no public notification or public response.

The fuel-security analysis assessed the need to implement OP 4 in each scenario in two parts: Actions 1 through 5 and Actions 6 through 11. Actions 1 through 5 are designed to work with transmission owners and other market participants to manage through stressed system conditions.[40] If Actions 1 through 5 are not sufficient to address the problem, the ISO may implement higher-level actions that may be more obvious to the public, such as voltage reductions and urgent appeals for public conservation.

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38. North American Reliability Corp., "Compliance & Enforcement," webpage (2016), http://www.nerc.com/pa/comp/Pages/Default.aspx.

Northeast Power Coordinating Council, "Standards," webpage (2017), https://www.npcc.org/Standards/default.aspx.

ISO New England, "Reliability Standards: Development and Compliance," webpage (2017), https://www.iso-ne.com/about/what-we-do/in-depth/reliability-standards-development-and-compliance.

39. ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (July 5, 2017), https://iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

40. In this study, demand-response resources were dispatched to reduce consumption when OP 4 Action 2 was implemented during times of system stress, reflecting the current actions available. However, on June 1, 2018, demand-response resources will be integrated into New England's wholesale energy markets and will be dispatched based on price in the same way generators are dispatched and will not be available as emergency resources. The study did not reflect this change because this will be the first time demand-response resources will be fully integrated into economic dispatch systems, so the price and other aspects of their offers, which affect when they will be dispatched to reduce energy consumption, is uncertain at this time. Real-time emergency generation, dispatched in Action 6, has been in decline due to environmental restrictions and will no longer be available as of June 1, 2018.

Table 2: ISO Operating Procedure No. 4 Actions

OP 4 Action	Action Description
1	▶ Implement a Power Caution, which is a public notification that electric power reserves can no longer be maintained using normal measures. Although full reserves are not being maintained, utility personnel will begin to take steps to manage these reserves. ▶ Advise resources with a capacity supply obligation (CSO) to prepare to provide capacity and notify "settlement-only" generators with a CSO to monitor reserve pricing to meet their obligations. ▶ Begin to allow the depletion of 30-minute reserves.
2	▶ Dispatch real-time demand resources in the amount and location required.
3	▶ Request voluntary load curtailment of market participants' facilities.
4	▶ Implement a Power Watch, which is a public notification that further steps to manage capacity could affect the public. Issue a public appeal for voluntary conservation.
5	▶ Schedule emergency energy transactions.
6	▶ Implement voltage reductions requiring more than 10 minutes. ▶ Dispatch real-time emergency generation.
7	▶ Request generation without a capacity supply obligation to provide energy for reliability purposes.
8	▶ Implement voltage reductions requiring 10 minutes or less.
9	▶ Request activation of transmission customer generation not contractually available to market participants during a capacity deficiency. ▶ Request voluntary load curtailment by large industrial and commercial customers.
10	▶ Implement a Power Warning. Issue urgent radio and TV appeal to the public for voluntary conservation. Public appeals are made when other efforts (e.g., emergency purchases, voluntary curtailment, contracted curtailment, and voltage reduction) have been unsuccessful in bringing supply and demand back into balance.
11	▶ Request state governors' support for ISO appeals for conservation.

ISO Operating Procedure No. 7

If OP 4 actions are not sufficient, the ISO may start depleting 10-minute reserves, which leaves the system vulnerable to uncontrolled outages that could cause significant damage to power system equipment and spread to other regions. If the 10-minute-reserves were depleted, implementation of controlled outages – rolling blackouts – could be required to maintain system balance. ISO New England Operating Procedure No. 7 (OP 7), *Action in an Emergency*, is the emergency procedure the ISO follows to implement load shedding.[41]

OP 7 is employed when there is unusually low frequency on the system, equipment overload, a capacity or energy deficiency, unacceptable voltage levels, or any other event the ISO deems an operating emergency in either an isolated or widespread area of the system. The objectives of OP 7 are as follows:

- Protect the reliable operation of the Eastern Interconnection
- Restore balance between customers' load and available generation in the shortest practicable time
- Minimize risk of damage to equipment
- Minimize interruption of customer service

When OP 7 is implemented, the ISO orders local control centers operated by transmission owners to reduce a specific quantity of system load. They do this by manually opening distribution system breakers to disconnect blocks of customers. Blocks of customers are disconnected and reconnected to the system sequentially, which is why load shedding is sometimes called "controlled outages" and "rolling blackouts." Rolling blackouts do not affect all customers in the affected area at the same time.

The study calculates the number of times each operating procedure would be needed throughout a 90-day winter in each scenario, the number of hours each procedure would be needed, and the quantity of consumer demand that would go unserved and for how long. These measurements, or metrics, of the number and severity of energy shortfalls illustrate the level of risk involved in each scenario and the relative benefits of the five key variables.

41. ISO New England Operating Procedure No. 7, *Action in an Emergency* (January 17, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

Study Results

The study results provide a basis for comparing the fuel-security risk of each of the 23 hypothetical resource combinations analyzed, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories, imports, and renewable resources. Although not all possible resource combinations were studied, the results show that some resource combinations would require more hours of emergency actions, while others would require fewer actions or none. Looking at all the scenarios together (see Figure 4 and Appendix A) provides perspective on the relative levels of fuel-security risk that could be present, depending on how the New England power system evolves, as well as approaches the region can consider to ensure power system reliability. The results should not be construed as a precise prediction.

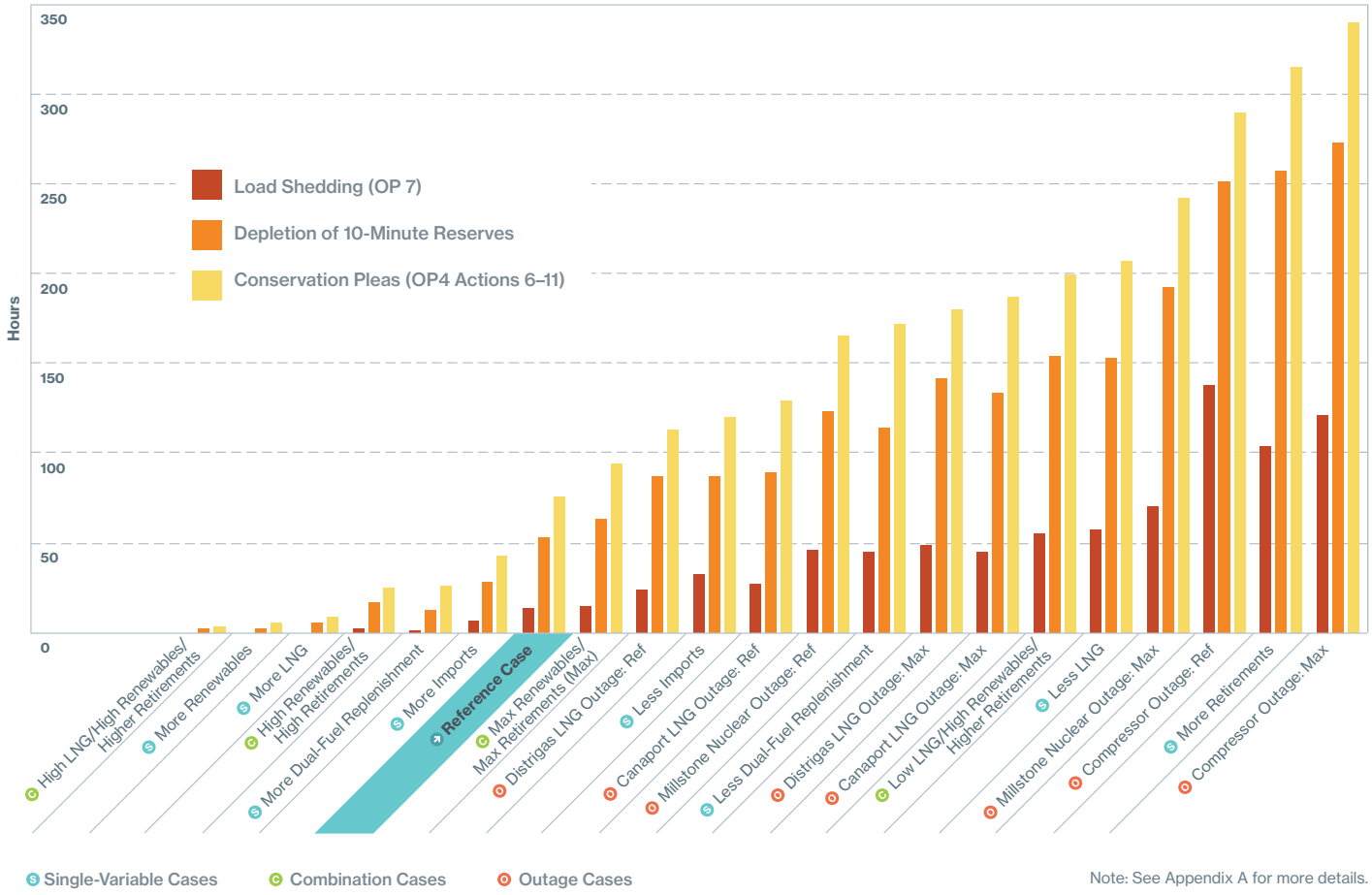
The results show that in most future power system scenarios studied, adequate levels of fuel would not be available throughout the entire winter. Without adequate fuel, the region's power plants would be unable to generate all the electricity needed to meet demand and required reserves – even after accounting for the demand-reducing effects of behind-the-meter solar arrays and energy-efficiency measures. The resulting energy shortfalls would require a range of operating procedures and emergency actions, up to and including load shedding.

Under the wide range of scenarios studied, in all but the most favorable future resource-mix combinations and in all key resource outage scenarios, the study shows that New England's fuel-security risk could become acute by winter 2024/2025, requiring frequent use of emergency actions. In some scenarios, energy shortfalls can be managed with relatively low-impact operating procedures that require no public notification or public actions to maintain system balance. However, most scenarios would require multiple hours of load shedding.

Current Trends Are Pushing the Power System toward Greater Risk

The major trends affecting the New England power system are moving in a negative direction. This analysis looked at a wide range of future resource mixes to assess the operational impact. All but one of the 23 modeled scenarios (the high [i.e., positive] boundary case, not shown here because it is unlikely to materialize) would lead to some level of emergency actions during winter 2024/2025 (i.e., OP 4 Actions 6–11), as well as hours when the ISO would have to deplete 10-minute reserves to keep the lights on. All but four scenarios would require some level of load shedding (i.e., OP 7). (The low [i.e., negative] boundary case resulted in even more hours of emergency actions but was omitted because it also is unlikely.)

Figure 4: Hours of Emergency Actions under Modeled Scenarios, Ordered Least to Most



A summary of the reference case and its results is presented below.

Reference Case

The reference case is a baseline scenario that represents a future resource mix, including low retirements and moderate levels of other variables, based on reasonable expectations that such levels will develop if the power system's evolution continues on its current path. It does not incorporate state policy goals and requirements for clean energy; other scenarios account for the potential effects of these initiatives on the region's resource mix. While the reference case results discussed below indicate tight operating

conditions, its purpose is to provide a point of orientation for all the other scenarios. Neither the reference case nor any of the other cases are predictors of the future, and none of the scenarios should be viewed as ISO New England's preferred scenario.

Reference Case Assumptions

- **Retirements: 1,500 MW.** The ISO projects that the region's 23 remaining coal- and oil-fired generators, with a capability of 5,400 MW, are at risk of retirement. The reference case assumes that by 2024, nine of these power plants, representing 1,500 MW, will be retired. This includes the remaining coal-fired power plants as a result of stricter emissions limits and economic pressures. The retirements in the reference case are in addition to the 4,200 MW recent and pending retirements that will be complete by 2019.

  None of the 22 other scenarios reduced retirements below the 1,500 MW reference case level; several increased retirements to 4,500 MW and some would retire all the remaining 5,400 MW of coal- and oil-fired power plants.

- **LNG injections: 1 Bcf/day.**[42] The maximum amount of regasified LNG that can be injected into New England's pipeline system is about 2.04 Bcf/d. In recent years, the most LNG injected at any one time into New England's pipeline system was 1.25 Bcf/d, on one day in February 2016. The reference case assumed that 1 Bcf is the maximum level of LNG that will be available for both heating and power generation on any given day. Less LNG would be needed on some days, and on some days, more.

- **Dual-fuel oil tank fill rate: two times per winter period.** Dual-fuel power plants' oil tanks in the reference case were assumed to be filled two times during the 90-day winter: once before the start of the winter and one more time during the winter. For example, a power plant with a 10,000-gallon tank will start the winter with a full tank and then refill it another time, for a total winter oil inventory of 20,000 gallons.

  The fill rate of two times was chosen because most generators' oil tanks hold about 10 days' worth of oil, so filling their tanks twice would allow most dual-fuel generators to burn oil for about 20 days. Environmental restrictions currently limit many oil-fired generators in New England to burning oil for no more than approximately 30 days per year. Running for 20 days would put most power plants near their annual limit, a moderate assumption for the reference case. The maximum fill rate in any of the scenarios was set at three times, which would put many generators at their annual limit.

  Massachusetts is implementing stricter emissions restrictions that will significantly reduce the amount of time generators in the state could run on oil, but the new Massachusetts regulations are not factored into the future scenarios. Another limitation not factored into the study was the fact that some dual-fuel generators have oil tanks that hold less than 10 days' worth of oil, limiting how long they can run on oil during a cold snap.

- **Imports: 2,500 MW.** The reference case assumes that the level of imports would be 2,500 MW because on average, over the last five winters, about 2,500 MW was flowing into New England from these neighboring grids just over 60% of the time; most of the rest of the

42. As shown in Figure 3, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities when necessary for their purposes. While these reserves aren't directly available to generators, they may sometimes make more natural gas available from other sources during the operating day.

time, about 2,000 MW was imported. The highest observed was about 4,000 MW, just 1% of the time. The study also assumed that if emergency actions were implemented, New England would receive an additional 500 MW of emergency imports from its neighbors, for a total of 3,000 MW of imports in the reference case.

- **Renewable resources: 6,600 MW.** The reference case assumed that New England's fleet of renewable resources will total 6,600 MW (nameplate) in winter 2024/2025, with no new wind or hydro imports. This incorporates the region's current renewable portfolio of about 2,200 MW of wind and other existing renewables such as biomass and refuse and solar resources. To this total, the reference case adds about 4,400 MW of new behind-the-meter solar PV forecasted to be installed by 2024. This estimate of future renewables provides a baseline for comparison from today to scenarios that incorporate additional renewables as planned or required by state legislation.

  None of the scenarios in this study reduced renewables below the reference case level of 6,600 MW.

Reference Case Results

The study found that in a severe winter in 2024/2025, a resource mix represented by the reference case could see multiple hours of emergency actions, including exposure to as many as 14 hours of load shedding spread over six days. Less severe emergency actions (OP 4 Actions 6 to 11) would be required for more than 75 hours, and the depletion of 10-minute reserves – often the last step before load shedding – would be needed for more than 50 hours (see Table 3).

Table 3: Reference Case Assumptions and Results

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case (Ref)	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

The study found that, while the assumed maximum available LNG of 1 Bcf/d was not needed every day in the reference case, it was needed on 35 days, and this still would not be sufficient to avoid load shedding or other emergency actions on six days.

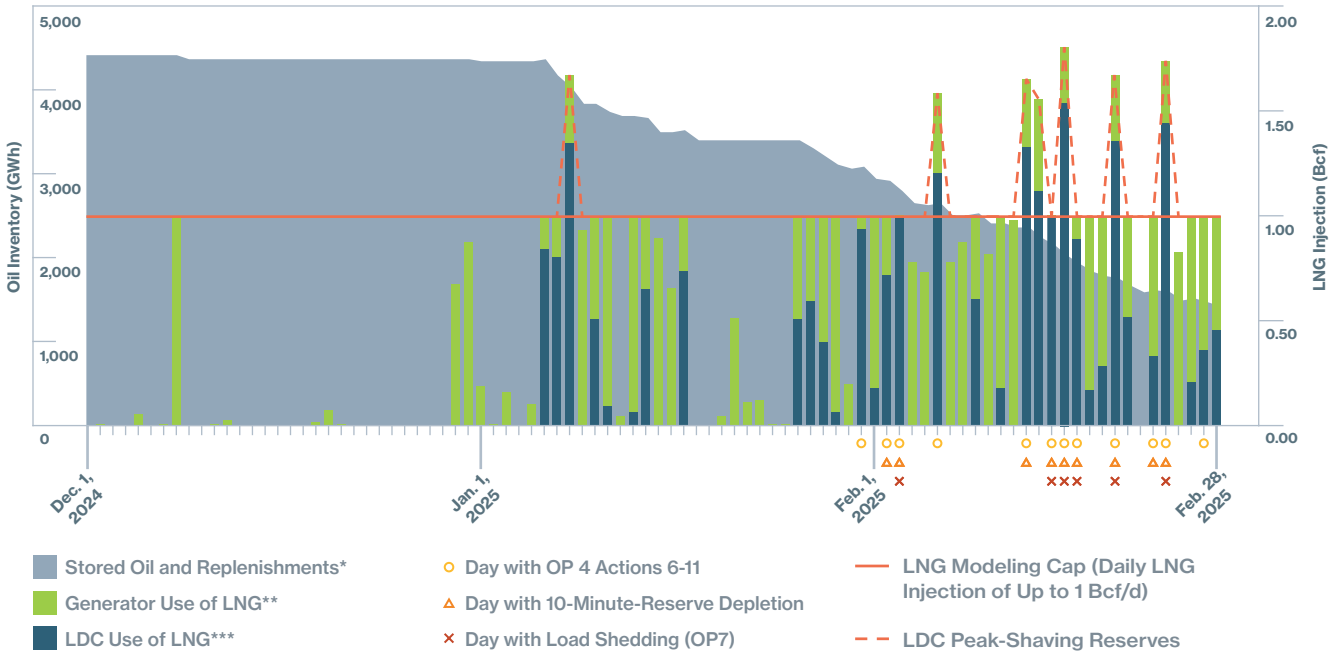
Overall, at the slightly higher load levels projected for 2024/2025 but with a cold winter like 2014/2015, the region as a whole would use 62.4 Bcf of LNG over the entire winter for both heating and power generation. This amount is significantly more than the 34.9 Bcf injected into the interstate pipelines, on average, over the past 10 winters and almost double the 31.6 Bcf of LNG injected during winter 2014/2015.

Figure 5 illustrates the daily use of LNG by both gas utilities to serve heating demand and power generators throughout the winter of 2024/2025 in the hypothetical reference case, which assumed a maximum of 1 Bcf/d of LNG injections. The graph also shows declining oil inventories, even in a scenario based on the assumption that dual-fuel oil tanks would be filled twice.

Emergency Actions Track LNG and Oil Availability

Building off Figure 3 on page 25, this chart takes a closer look at the relationship between regional LNG supply and demand, declining oil inventories as winter progresses, and system reliability. On days when LDC demand for LNG is high, less natural gas is available for generators. When LDC demand stresses the capacity of the natural gas infrastructure, LDCs can tap into LNG reserves stored at their "peak-shaving" facilities. While these reserves aren't directly available to generators, their use may sometimes make more natural gas available during the operating day. The model shows that as winter progresses, oil inventories decline, while days with high heating demand tend to occur more often. If all or most of the LNG is being used for heating when oil inventories have declined, the region will likely require more frequent emergency actions on the power system (e.g., pleas for energy conservation [OP 4 Actions 6–11] and load shedding [OP 7]).

Figure 5: Projected Winter 2024/2025 Oil and LNG Use and Emergency Actions
(Reference Case)



* Includes distillate and residual oil. This scenario assumed dual-fuel units' oil tanks would be filled twice: the initial inventory before winter and one replenishment during winter.

**Graph does not include the Mystic 8 and 9 gas-fired generators' fuel use or supply from the LNG facility.

***LDC use includes the Maritimes' gas utility demand. LDC data are from ICF International, New England LDC Gas Demand Forecast Through 2030 (December 14, 2016, presentation to Planning Advisory Committee).

Single-Variable Scenarios

The results are summarized below for the eight favorable and unfavorable scenarios that changed just one variable. Each of the favorable and unfavorable scenarios increased or decreased one key variable from the reference case baseline. (The exceptions were retirements, which were never dropped below the reference case level of 1,500 MW; and renewables, which never dropped below 6,600 MW, and in the case of higher renewables, was assigned a higher level of imports to reflect clean energy imports over a new transmission line.)

The study also included a best-case scenario (*High Boundary*), where all five variables were modeled at levels that would minimize fuel-security risk, and a worst-case scenario (*Low Boundary*) in which all five variables were modeled at less favorable levels that would raise fuel-security risk. At opposite ends of the spectrum, these two cases illustrated the best and worst outcomes but represent future resource combinations that are highly unlikely to materialize. Because they are considered unlikely scenarios, the results of these scenarios are not included in charts but are detailed in the matrix in Appendix A.

The single-variable scenarios with favorable inputs required from 0 to 7 hours of load shedding. The negative, single-variable scenarios, with the least favorable inputs, required load shedding ranging from 33 to 105 hours.

Figure 6 illustrates the range of OP 4 emergency-procedure hours resulting from each of the "plus" (favorable level) and "minus" (unfavorable level) single-variable cases. Figure 7 shows the range of OP 7 emergency-procedure hours for the single-variable cases.

Levels of Five Variables Are Key to Fuel-Security Risk

The single-variable cases explore the range of impacts of each of the five individual variables studied, as illustrated by these graphs. Each bar spans a variable's results from a high amount (⊕) through the reference case level (⊖) and down to a low amount (⊖). Results in the first graph are measured in OP 4 emergency-action hours, which are an indicator of system stress and may involve public pleas for energy conservation. In the second graph, results are measured in OP 7 hours, which represent load shedding. Compared with the reference case, increased inputs lead to decreased risk – and vice versa (with the exception of retirements because more retirements lead to increased risk). No single variable eliminated all risk. Notably, decreases in each variable had proportionally greater negative effects, despite being of comparable value to the increases. The region's vulnerability to resource retirements and decreases in LNG availability is particularly evident.

Figure 6: Ranges of OP 4 Hours in Single-Variable Cases

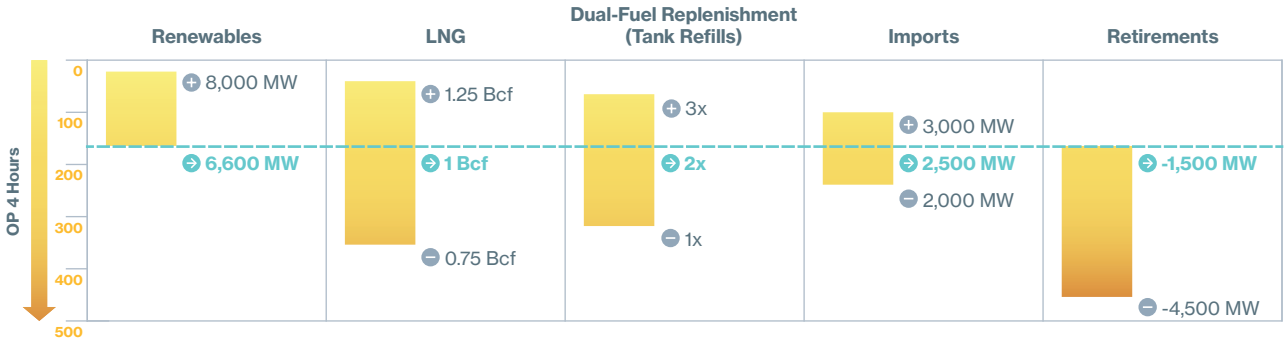
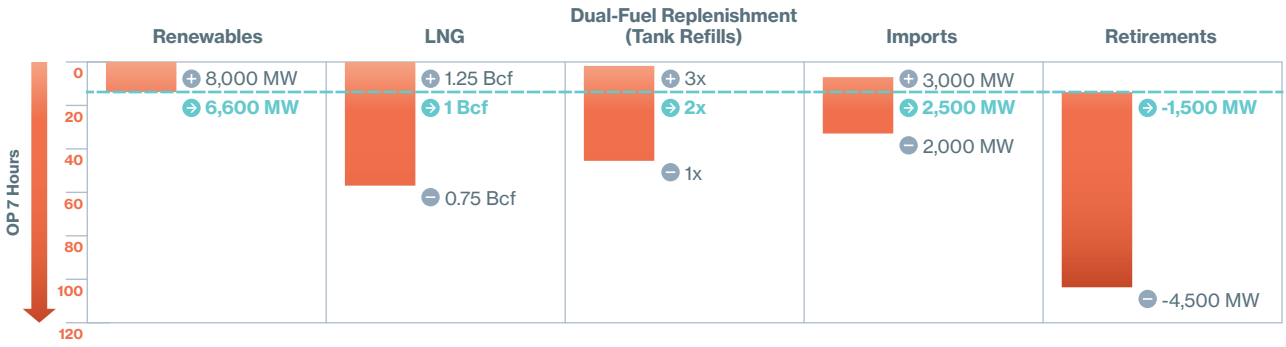


Figure 7: Ranges of OP 7 Hours in Single-Variable Cases



Range of OP 4 Hours Spanning Plus and Minus Cases
Range of OP 7 Hours Spanning Plus and Minus Cases
⊕ High-Case Input Value
⊖ Low-Case Input Value
Reference Case Hours
Reference Case Input Values

Note: See Appendix A for more details.

Renewable Resources

As shown in Table 4, no load shedding was required for the positive, single-variable scenario that increased renewables to 8,000 MW and imports to 3,500 MW (to represent an additional 1,000 MW of clean energy over a new transmission tie to a neighboring system).

The high-renewables scenario resulted in 29 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the scenario required 54.6 Bcf total LNG injections over the entire winter.

Table 4: Assumptions and Results for the Scenario with More Renewables Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More Renewables	–1,500	1.00	2	3,500	8,000	29	24	6	2	0	0
→ Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

LNG

The favorable single-variable scenario raised LNG injections to 1.25 Bcf/d, which equals the highest daily LNG injection seen at any one time in the last nine years. This scenario required no load shedding (refer to Table 5). The unfavorable LNG scenario posited a maximum injection of 0.75 Bcf/d. The lower LNG injections required 58 hours of load shedding over 10 days.

The high LNG scenario resulted in 32 days when at least 95% of the assumed maximum LNG injection of 1.25 Bcf/d was being used. Over the entire winter in this scenario, 71 Bcf of LNG was used in New England. The low LNG scenario resulted in 39 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was injected, and the region used 52.4 Bcf of LNG over the entire winter.

Table 5: Assumptions and Results for the Scenarios with More and Less LNG Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More LNG	–1,500	1.25	2	2,500	6,600	32	40	9	6	0	0
→ Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less LNG	–1,500	0.75	2	2,500	6,600	39	355	208	153	58	10

Imports

Table 6 shows the results for the scenarios with more or less imports. The favorable single-variable scenario that raised imports to 3,000 MW, a level that was seen just 35% of the time during the winter period over the past five years, required 7 hours of load shedding over 4 days. The case that reduced imports to 2,000 MW, the level of imports seen on most days over the last five winters, required 33 hours of load shedding over 7 days.

The high-imports scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, with 60 Bcf/d imported for the winter. The low-imports scenario resulted in 36 days when at least 95% of the LNG was being used, up to the assumed maximum of 1 Bcf/d, and the region used 64.8 Bcf/d over the 90 days of winter.

Table 6: Assumptions and Results for the Scenarios with More and Less Imports Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More Imports	–1,500	1.00	2	3,000	6,600	35	103	43	28	7	4
→ Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Imports	–1,500	1.00	2	2,000	6,600	36	239	120	87	33	7

Dual-Fuel Replenishment

The scenario that increased the number of times dual-fuel generators' oil tanks were filled to three times during the winter – which would theoretically max out most generators' 30-day limit for running on oil – showed just one hour of load shedding on one day. The scenario that lowered the number of times oil tanks were filled to just once during the winter showed 46 hours of load shedding over 10 days. Refer to Table 7.

Both the high-oil-tank and low-oil-tank inventories scenarios resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Both the high-oil and low-oil inventories scenarios used 62.4 Bcf total LNG over the course of the winter.

Table 7: Assumptions and Results for the Scenarios with More and Less Dual-Fuel Replenishment Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More Dual-Fuel Replenishment	–1,500	1.00	3	2,500	6,600	35	69	26	13	1	1
→ Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Dual-Fuel Replenishment	–1,500	1.00	1	2,500	6,600	35	317	173	115	46	10

Retirements

The unfavorable single-variable scenario that increased coal- and oil-fired power plant retirements to 4,500 MW had the worst outcomes among the single-variable cases: 105 hours of load shedding over 16 days, and 455 hours of all OP 4 actions as well as the depletion of 10-minute reserves during 258 hours of those OP 4 hours. The high-retirements scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the region used 62.4 Bcf/d over the winter. Table 8 summarizes the results for the high-retirements scenario.

Table 8: Assumptions and Results for the Scenario with More Retirements Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
More Retirements	–4,500	1.00	2	2,500	6,600	35	455	316	258	105	16

Combination Scenarios

The four combination cases each altered several variables at one time to develop a combination of future resource mixes that reflect several possible future power systems. All these cases included higher levels of renewables, which could be considered a proxy for greater levels of EE that reduce consumer demand for power; adding renewables would reduce the need to turn to stored fuels.

All the combination cases also added 1,000 MW to imports to bring the total to 3,500 MW. By increasing imports by 1,000 MW, these scenarios account for the Massachusetts requirement for about 1,200 MW of clean energy, such as hydro or wind energy imported from Canada or New York over a new high-voltage transmission line. All the combination cases also assumed oil tanks were filled twice during the winter.

Combination LNG Scenarios (High LNG and Low LNG with High Renewables/Higher Retirements)[43]

Two combination cases included high levels of renewables, at 8,000 MW, with imports at 3,500 MW, and higher levels of retirements, at 4,000 MW, with one case reducing LNG injections to 0.75 Bcf/d and the other increasing LNG injections to 1.25 Bcf/d. As shown in Table 9, the combination case with higher LNG injections showed no load shedding, while the combination case with low LNG injections resulted in 56 hours of load shedding over 12 days.

43. The case names refer to the labels included on the detailed results matrix in Appendix A as well as the smaller tables included with the scenario results in the body of the report.

The high LNG combination scenario showed total LNG injections of 61.6 Bcf and resulted in 23 days when at least 95% of the assumed maximum of 1.25 Bcf/d LNG was being used. The low LNG injections scenario resulted in total LNG consumption of 46.3 Bcf over the winter and 35 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was being used.

Table 9: Assumptions and Results for the Combination LNG Scenarios Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High LNG/ High Renewables/ Higher Retirements	–4,000	1.25	2	3,500	8,000	23	18	4	2	0	0
Low LNG/ High Renewables/ Higher Retirements	–4,000	0.75	2	3,500	8,000	35	358	200	154	56	12

Combination Scenario with High Retirements (High Renewables/High Retirements)

The third combination scenario doubled the reference case retirements of non-gas-fired units to 3,000 MW. The scenario also set renewables and imports to 8,000 MW and 3,500 MW, respectively, and held the maximum LNG injections level with the reference case at 1 Bcf/d. With high retirements, renewables, and imports, the third combination case resulted in just 2 hours of load shedding on one day. This scenario also resulted in total LNG injections of 54.6 Bcf over the winter and 29 days when at least 95% of the assumed maximum of 1 Bcf/d LNG was being used. Table 10 shows these results.

Table 10: Assumptions and Results for the Combination Scenario with High Retirements Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High Renewables/ High Retirements	–3,000	1.00	2	3,500	8,000	29	84	25	17	2	1

Combination Scenario with Maximum Renewables and Maximum Retirements (Max Renewables/Max Retirements, or Max)

The fourth combination scenario assumed that the region's entire fleet of coal- and oil-fired generators had retired, totaling 5,400 MW. The case also assumed that the region's fleet of renewables had grown to 9,500 MW, the maximum level used in the study. This scenario added about 900 MW to the PV forecast, bringing the total PV to 5,300 MW. The projected level of offshore wind was increased by another 400 MW above the 1,600 MW offshore wind requirements of the Massachusetts energy legislation, to 2,000 MW. This scenario also increased imports to 3,500 MW, incorporating 1,000 MW of clean energy imported from neighboring systems.

This scenario could be considered akin to the effects of implementing strict carbon reduction goals or using other regulations to significantly limit carbon emissions from power plants. Carbon-reduction initiatives would attract higher levels of renewables and drive more fossil-fuel-fired generators to retirement.

In the scenario, with high retirements and high renewables, 15 hours of load shedding over 6 days was needed, and 52.9 Bcf of LNG was required over the winter, resulting in 23 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Refer to Table 11.

Table 11: Assumptions and Results for the Combination Scenario with Maximum Retirements and Renewables Compared with the Reference Case

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Max Renewables/ Max Retirements (Max)	–5,400	1.00	2	3,500	9,500	23	206	94	64	15	6

Outage Scenarios

Eight outage scenarios show the consequences of four possible high-impact events involving the outages of important energy facilities for an entire winter**.** Outages of shorter duration would also create significant system stress and could require the implementation of emergency actions. Each of the outages was modeled twice: on a system represented by the reference case (*Ref*) and on a system represented by the combination case that includes the maximum levels of retirements and renewables assumed in the study (*Max Renewables/Max Retirements [Max]*).

The winter-long outages of the following facilities were modeled:

- A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and restricting fuel to about 7,000 MW of generation for the entire winter
- The loss of Millstone Nuclear Power Station in Connecticut, one of the region's remaining two nuclear stations, eliminating 2,100 MW of baseload power
- The loss of the Canaport LNG import and regasification facility in New Brunswick, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems
- A disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems and the local gas utility's distribution system

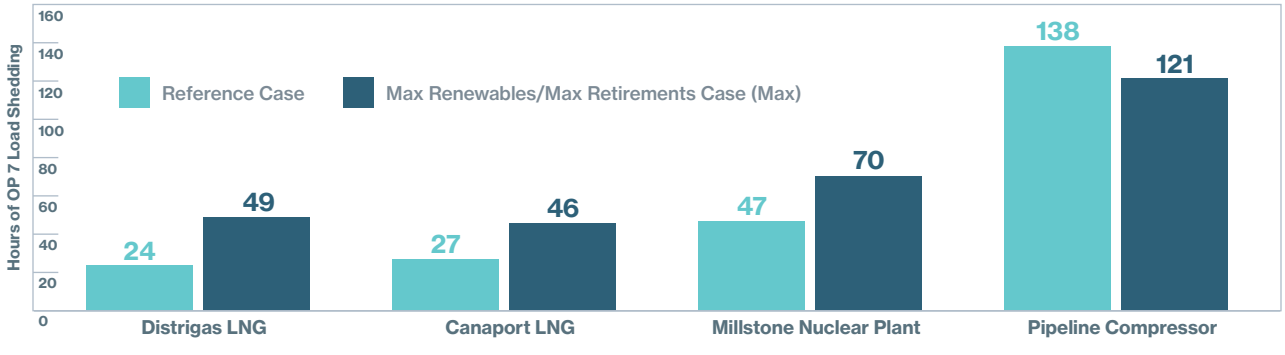
Figure 8 shows the projected hours of load shedding resulting from a season-long outage of a major fuel or energy source in the reference and *Max* cases.

Some variables in the reference and *Max* cases were adjusted to reflect the expected consequences of each outage. For example, the reference case assumes that 1 Bcf/d would be the maximum LNG injection available on any given day. But if a compressor station went out for the entire winter, natural gas prices would rise and LNG suppliers would be expected to ship more LNG to New England. Similarly, higher natural gas prices mean higher wholesale electricity prices in New England, so dual-fuel generators could be expected to fill their tanks more often to ensure they would have fuel to run when prices were high.

High Levels of LNG, Oil, Imports, and Renewables Would Not Eliminate Load Shedding if a Major Energy Facility Goes Out

This graph shows the projected hours of load shedding (i.e., OP 7) that would result from the season-long loss of the Distrigas LNG terminal, Canaport LNG terminal, the Millstone nuclear plant, or an interstate pipeline compressor station. The study looked at the impacts of each of these outages in both the reference case and Max case, with the highest amount of renewables and retirements. It is worth noting that even the most aggressive increases in LNG, oil, and renewables would not prevent the need for load shedding, particularly during a pipeline compressor station outage. These winter-long outage scenarios also hint at the severe impact of a shorter-term outage, which would provide less time for the markets to mobilize other fuel or energy sources.

Figure 8: Projected Hours of Load Shedding due to Season-Long Outage of a Major Fuel or Energy Source
(Reference Case Compared with the Max Scenario)



Note: See Appendix A for more details.

Compressor Outage

As outlined above, the winter-long loss of a natural gas pipeline compressor station would likely spur higher imports of LNG and more frequent oil tank refills. Taking that into account, the maximum LNG injection assumed in both the reference and combination scenarios was increased from 1 Bcf/d to 1.5 Bcf/d, higher than the highest coincident injection of 1.25 Bcf/d seen on any one day in the region. These scenarios also assumed oil tanks were filled three times, rather than twice. Even with additional LNG and oil, the compressor station outage in the reference case (*Compressor Outage: Ref*) would have the highest number of load-shedding hours (apart from the unlikely worst-case scenario), at 138 hours over 17 days. On a power system represented by the scenario with the maximum level of retirements and renewables (*Compressor Outage: Max*), 121 load-shedding hours over 19 days would be needed. Table 12 shows the assumptions and results for this scenario.

Over 17 days, 138 hours of load shedding would equate to about eight hours per day, though given the variations in system conditions from day to day and hour to hour, such an even distribution of load shedding would be unlikely. Some days would have less than eight hours of load shedding; some would have more.

The compressor station outage in the reference case resulted in 127.8 Bcf of total LNG injections over the winter, while the outage in the combination scenario required 112.2 Bcf. Both are far higher than the highest level of LNG delivered to New England pipelines, which was 73 Bcf in winter 2010/2011. The reference case and combination cases resulted in 47 days and 41 days, respectively, when at least 95% of the assumed maximum daily LNG injection of 1.5 Bcf/d was being used.

As these results illustrate, a pipeline compressor outage would have a significant impact on New England's power system because of the region's limited network of pipelines; most or all the limited natural gas that could get into New England would go to gas utilities serving their heating customers.

Table 12: Assumptions and Results for the Pipeline Compressor Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Compressor Outage: Ref	–1,500	1.50	3	2,500	6,600	47	458	290	252	138	17
Compressor Outage: Max	–5,400	1.50	3	3,500	9,500	41	510	340	273	121	19

Millstone Nuclear Outage

The winter-long outage of a nuclear power station was incorporated into the hourly dispatch employed by the study model, rather than represented as an input variable. The model assumed that Millstone, a 2,100 MW nuclear power plant, which would usually be among the first resources dispatched every day, would not be available for the entire winter. Without this baseload resource, more resources using other

fuels, including natural gas, oil, and LNG, would be needed more often, depleting their fuel sources. In the reference case, the nuclear outage (*Millstone Nuclear Outage: Ref*) would require 47 hours of load shedding over 10 days. Refer to Table 13.

In the nuclear outage case with maximum retirements and maximum renewables (*Millstone Nuclear Outage: Max*), more renewables would help when available, but the absence of all coal- and oil-fired generators coupled with the nuclear outage would mean virtually all the power plants with stored fuel in New England would be unavailable. The result would be 70 hours of load shedding over 12 days.

The Millstone reference case outage resulted in 72.9 Bcf total LNG injections over the winter – about the same as the most wintertime LNG deliveries seen to date – and 42 days when at least 95% of the assumed maximum daily LNG injection of 1 Bcf/d was being used. The nuclear combination case outage resulted in total LNG injections of 61.6 Bcf over the winter, and 36 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used.

Table 13: Assumptions and Results for the Millstone Nuclear Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Millstone Nuclear Outage: Ref	–1,500	1.00	3	2,500	6,600	42	349	166	124	47	10
Millstone Nuclear Outage: Max	–5,400	1.00	3	3,500	9,500	36	389	243	193	70	12

Distrigas LNG and Mystic 8 and 9 Outage

On a power system represented by the reference case, the outage of Distrigas, one of the region's three LNG import facilities and the nearby Mystic 8 and 9 generating units fueled by that imported LNG, would cause 24 hours of load shedding over seven days (*Distrigas LNG Outage: Ref*), as shown in Table 14. If the outage occurred on a system with maximum retirements and maximum renewables, twice as many load shedding hours would be required, at 49 hours over 11 days (*Distrigas LNG Outage: Max*).

The Distrigas outage in the reference scenario resulted in 50.9 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. The *Distrigas LNG Outage: Max* scenario resulted in total LNG injections of 43.8 Bcf over the winter, and 34 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. While this scenario assumed that the Distrigas LNG import facility would be out of service during the entire winter, maximum LNG injections were not reduced below 1 Bcf/d because it was assumed the region's other two LNG facilities would increase their imports.

Table 14: Assumptions and Results for the Distrigas and Mystic 8 and 9 Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Distrigas LNG Outage: Ref	–1,500	1.00	3	2,500	6,600	41	276	114	87	24	7
Distrigas LNG Outage: Max	–5,400	1.00	3	3,500	9,500	34	346	181	142	49	11

Canaport LNG Terminal Outage

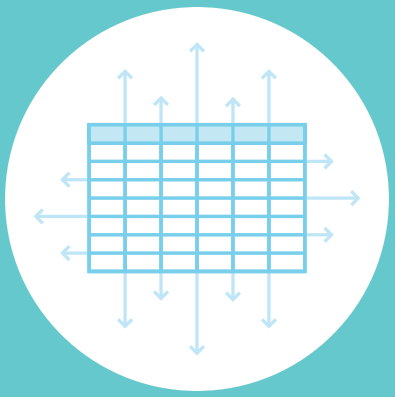
The season-long outage of the large Canaport LNG import facility in Canada would reduce the LNG available to inject into New England's pipeline system. The study reflects this by reducing LNG injections to 0.65 Bcf/d, the lowest level assumed in any scenario. In the reference case, the outage would cause load to be shed 27 hours over nine days (*Canaport LNG Outage: Ref*). In the scenario with maximum retirements and maximum renewables, the outage would require 46 hours of load shedding over 11 days (*Canaport LNG Outage: Max*). Refer to Table 15.

The Canaport LNG import facility outage in the reference scenario resulted in 48.1 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used. The *Canaport LNG Outage: Max* resulted in 41.4 Bcf total LNG injections over the winter and 35 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used.

Table 15: Assumptions and Results for the Canaport LNG Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT: Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Canaport LNG Outage: Ref	–1,500	0.65	3	2,500	6,600	41	270	129	90	27	9
Canaport LNG Outage: Max	–5,400	0.65	3	3,500	9,500	35	354	187	134	46	11

Key Findings



Key findings from the report include:

- **All four outage scenarios** involving the winter-long loss of key energy facilities produced the most severe outcomes, illustrating the region's vulnerability to these sources. Each outage of a natural gas pipeline compressor station, a nuclear station, or one of the region's LNG import facilities resulted in hundreds of hours of operating procedures and emergency actions and between two dozen and more than 100 hours of load shedding. The loss of a compressor station was particularly problematic, given the resulting reduction in natural gas supply in New England. The local gas utilities would fully use their firm capacity rights on other pipelines and secure priority rights to the region's LNG facilities for many more hours. This would further reduce the natural gas available to power plants, with the results showing more than 120 hours of load shedding spread across 19 days.
- **Two combination cases *(High LNG/High Renewables/Higher Retirements* and *High Renewables/High Retirements)*** showed that higher levels of retirements of oil- and coal-fired power plants could be addressed with higher levels of LNG, imports, and renewables, resulting in fewer hours of emergency actions, less need to deplete operating reserves, and very limited exposure to load shedding. These cases' inputs fall in the range between the reference case and the scenario with maximum retirements and maximum renewables, indicating that the power system can be expected to remain extremely vulnerable to the outages of any of the region's key energy suppliers.
- **A combination case *(Low LNG/High Renewables/Higher Retirements)*** with a high level of retirements of non-gas-fired generators coupled with lower LNG injections required frequent emergency actions and multiple hours of load shedding, despite higher levels of imports and renewables.
- **The combination case *(Max Renewables/Max Retirements)*** with maximum retirements and maximum renewables illustrated the impacts of retiring every at-risk coal- and oil-fired generator in the region and developing the highest level of renewable resources. With moderate levels of LNG, imports, and oil tank inventories, more than 200 hours of emergency actions and more than a dozen hours of load shedding over six days were required to maintain system balance. The outage scenarios based on this combination case demonstrated that the loss of a key energy facility would exacerbate the use of emergency procedures.

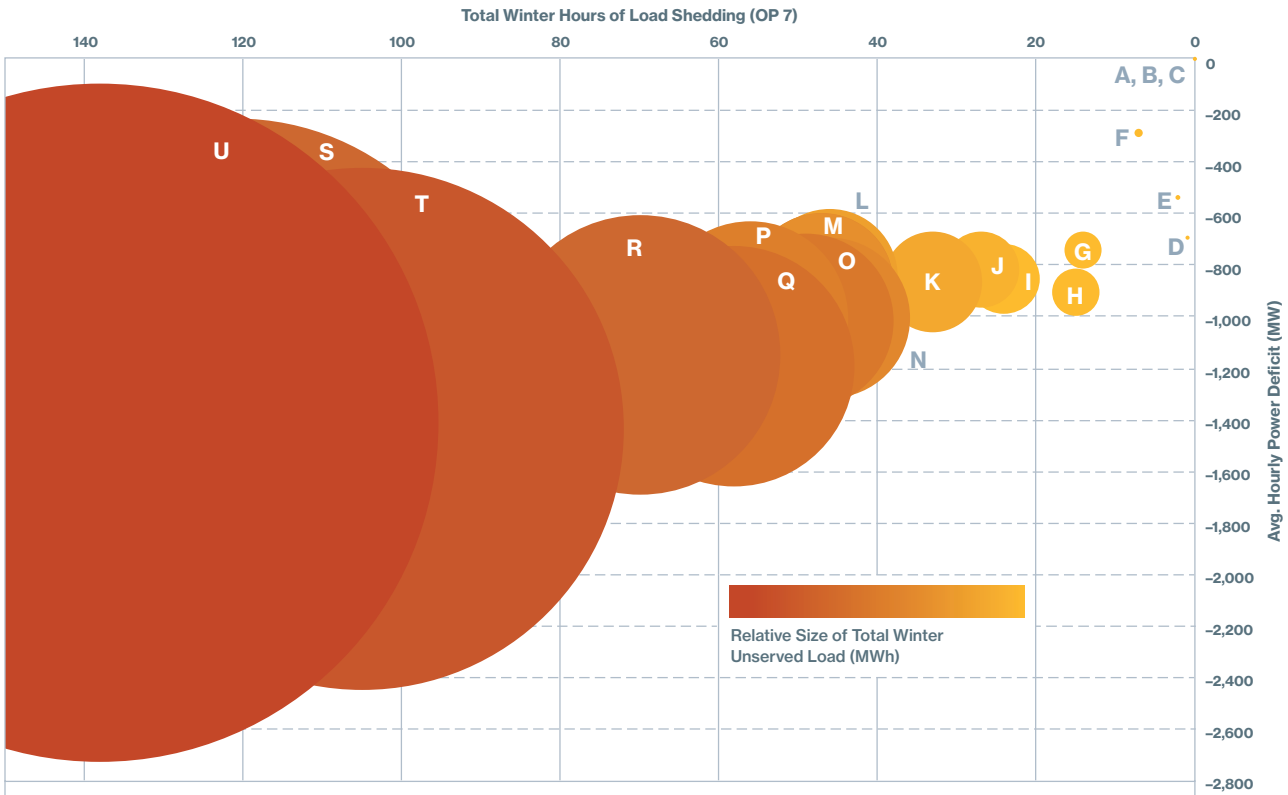
- **The single-variable cases** that raised or lowered just one variable showed the following:
  - **The retirements of oil- and coal-fired power plants** have the greatest impact among the five variables on increasing the region's fuel-security risk, as measured by the frequency and duration of energy shortfalls requiring emergency actions. The scenarios that raised the level of retirements saw a seven-fold increase in OP 7 hours over the reference case. Other negative variables increased load shedding to no more than four times the reference case level.
  - **Lower LNG injections** have the next-greatest impact on increasing the region's fuel-security risk**,** increasing load shedding to nearly 60 hours compared with 14 hours in the reference case. **Conversely, higher LNG injections** have a significant impact on reducing the region's fuel-security risk – the higher LNG case had no load shedding and far fewer hours of emergency actions.
  - **Increased oil inventories at dual-fuel generators** also significantly improve fuel security. The single-variable scenario that increased the number of times dual-fuel power plants could replenish their oil inventory showed relatively lower levels of system stress, including just one hour of load shedding.
  - **Large amounts of renewable resources combined with additional imports** lowered the fuel-security risk compared with the reference case, with no load shedding and a greatly reduced need for emergency actions.
- **The two boundary cases that moved all variables in either the most favorable or least favorable direction** showed the most positive or negative results, as would be expected. But each of the boundary scenarios would require all five variables to evolve in the same direction, which is unlikely.

Figure 9 reflects the magnitude of load shedding (i.e., OP 7) in all but the high and low boundary scenarios, with the bubble size depicting the total projected megawatt-hours (MWh) of unserved load. One megawatt-hour is the amount of energy produced by 1 MW over one hour. A power resource of 500 MW capacity, for example, will provide 1,000 MWh of energy if it operates at this capacity for two hours. In New England, 1 MWh can serve the equivalent of approximately 860 homes for one hour, on average. This study assumed New England would have sufficient resource *capacity* (megawatts) to meet future demand in winter 2024/2025, and instead focused on the ability of that capacity to generate *energy* over time (megawatt-hours). Megawatt-hours of energy shortfalls – or unserved load – demonstrate how fuel availability can ultimately determine a resource's actual output over the course of an entire winter, regardless of its capacity.

The Greatest Risks Come from Major Outages, More Retirements, and Lower LNG and Oil Supplies

This chart reflects the magnitude of load shedding (i.e., OP 7) in each of the scenarios. (The high and low boundary cases were omitted.) The bubble size represents the total megawatt-hours of load shedding for the winter, illustrating the region's vulnerability to outages of major energy facilities, increases in retirements, and drops in LNG or oil supplies.

Figure 9: Magnitude of Load Shedding in Modeled Cases



Cases Ordered by Total Winter Unserved Load (MWh), Least to Most:

Case	MWh	Case	MWh	Case	MWh
A) High LNG/High Renewables/ Higher Retirements (C)	0	H) Max Renewables/ Max Retirements (Max) (C)	13,609	O) Distrigas LNG Outage: Max (O)	49,805
B) More Renewables (S)	0	I) Distrigas LNG Outage: Ref (O)	20,496	P) Low LNG/High Renewables/ Higher Retirements (C)	56,518
C) More LNG (S)	0	J) Canaport LNG Outage: Ref (O)	22,026	Q) Less LNG (S)	69,179
D) More Dual-Fuel Replenishment (S)	696	K) Less Imports (S)	28,608	R) Millstone Nuclear Outage: Max (O)	80,312
E) High Renewables/ High Retirements (C)	1,070	L) Canaport LNG Outage: Max (O)	38,819	S) Compressor Outage: Max (O)	149,574
F) More Imports (S)	2,031	M) Millstone Nuclear Outage: Ref (O)	41,080	T) More Retirements (S)	150,297
G) Reference Case	10,397	N) Less Dual-Fuel Replenishment (S)	46,232	U) Compressor Outage: Ref (O)	194,705

(S) Single-Variable Cases (C) Combination Cases (O) Outage Cases

Note: See Appendix A for more details.

Conclusions

For New England, the foremost risk to current and future power system reliability revolves around fuel security – the ability of power plants to get the fuel they need to run, when they need it.

This operational fuel-security assessment has quantified the level of risk in a wide range of possible future resource combinations and provides information the region can use to consider approaches to ensuring power system reliability. The diversity of scenarios was designed to help ISO New England and its stakeholders better understand how well these future power system profiles, or other profiles that fall between them, could support power system reliability throughout an entire winter.

The study results indicate the risk of future energy shortfalls is greater than the risk today. All but one of the 23 scenarios show that the regional power system could frequently experience some degree of system stress, requiring system operators to employ emergency procedures. All but four scenarios show that some level of load shedding would be needed to maintain system balance. This indicates that the region is currently maintaining a delicate balance that could easily be disrupted if any of the five key variables – retirements of coal- and oil-fired generators, LNG injection levels, the availability of oil as well as the permitted ability to burn oil, electricity imports, and the development of renewable resources – trend in a negative direction at an accelerated rate.

This fuel-security analysis also illustrates the acute vulnerability of New England's power system to the loss of any one of several key energy facilities. The region is particularly vulnerable to an outage at a natural gas pipeline compressor station.

Outages

The regional dependency on several key facilities is a particular concern highlighted by this study. An extended outage at any one of these key facilities – a natural gas pipeline compressor station, the Distrigas LNG import facility in Massachusetts and the Mystic 8 and 9 generators it fuels, the Canaport LNG import facility in Canada, or the Millstone nuclear power plant – would result in frequent energy shortages that would require frequent and long periods of rolling blackouts.[44] While outages of shorter duration were not studied, the importance of these facilities to system reliability is highlighted by the results of this fuel-security study. An outage at any of these facilities, regardless of duration, would likely create significant system stress.

44. Potomac Economics *2016 Assessment of the ISO New England Electricity Markets*, report of the ISO New England external market monitor (June 2017), p.22, https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf. "In the Baseline scenarios shown in Figure 7, LNG capacity would become pivotal for meeting generators' demand in 2023/24, even if the oil storage is fully utilized."

The reliability impact of any one of these outages cannot be eliminated, even on a system with more LNG, oil inventory, and imports, the study shows. Each outage scenario would require load shedding that could affect hundreds of thousands of average New England homes at a time.

A compressor station outage on a major natural gas pipeline would have the most severe impact on power system reliability, requiring the most frequent and extensive load shedding of all the scenarios, aside from the unlikely negative boundary scenario. Frequent load shedding would be required even in a scenario with the likely increase in imports of LNG and electricity, as well as greater use of oil inventories by dual-fuel power plants and very high levels of renewable resources.

The ISO's ability to address this high-impact scenario is limited to designing operational procedures to ensure that if such a compressor station or pipeline outage occurs, system stability can be maintained and cascading outages are prevented. The impact of such an outage can be mitigated through the use of increased LNG and imported electricity, as well as greater renewable resources and dual-fuel capacity with enhanced strategies for replenishing oil tank inventories.

Stored Fuels: Imported LNG, Electricity Imports, and Dual-Fuel Capability

The study illustrates that over the next several decades, New England's power system will largely depend on the availability of two key elements: sufficient injections of LNG and electricity imports from neighboring regions. However, the availability of LNG and imports may be subject to some forces that are outside the purview of ISO New England and New England's policymakers.

Additional dual-fuel capability, which will increase the inventory of stored oil available to generate electricity when other fuels are not available in sufficient quantities, would also provide a key contribution to power system reliability. However, state emissions requirements are tightening, which will limit the amount of time some generators can run on oil, and obtaining permits to construct new dual-fuel generators is becoming more difficult.

LNG injections from import terminals in the east and Canada have provided important supplements to pipeline gas and have helped support New England's power system reliability, but as demand for natural gas for heating rises and pipeline capacity remains the same, more local gas utilities are contracting for LNG to serve their customers. Further, as natural gas fields in Atlantic Canada are depleted, the Maritimes' demand for natural gas from pipelines and LNG import facilities is expected to rise. In the future, less LNG may be available for power plants in New England. But at the same time, the continuing retirements of oil- and coal-fired power plants, which use fuel stored on site, will increase New England's reliance on imported LNG.

Robust levels of imported electricity from neighboring power systems are essential to continued power system reliability. However, imports also present a degree of uncertainty and risk. Each scenario assumes a level of imports at least twice the amount obligated through the Forward Capacity Market.[45] In other words, half the imports assumed in the study may not be available if the neighboring area where they are located needs them. This is important because Québec, New York, and New Brunswick all experience winter weather at the same time as New England. The question is whether New England's neighbors will have enough electricity to serve their own customers and supply New England with all the electricity

45. Resources that clear in the annual Forward Capacity Market auction administered by ISO New England take on an obligation (called a capacity supply obligation, or CSO) to be available in the relevant capacity commitment period. In return, they receive a monthly payment based on the auction clearing price and the number of megawatts they promised to make available.

assumed in the scenarios. Also, New York and New Brunswick, as well as New England, all depend on imports from Québec. A power system contingency in Québec can deplete its exports and have a domino effect on its neighbors.[46]

Further, as New York's power system evolves away from oil-fired and nuclear plants with on-site fuel, and toward increased dependence on natural gas and renewables, the extent of the New York system's ability to support electricity exports to New England is unclear. Also unclear is whether this trend will reduce the availability of pipeline gas supplied to New England.

With the increasing retirements of generators with stored fuels (nuclear, coal, and oil), the region's reliance on imported fuels and electricity is likely to grow. Greater levels of dual-fuel capability, which would enable natural-gas-fired generators to turn to oil stored onsite when they can't get gas, helps system reliability.

Logistics

Some resource mixes pose less fuel-security risk than others, but all scenarios are subject to the unquantifiable uncertainties of fuel-delivery logistics, weather, and events that unfold on the power grid more randomly than can be represented in a study of this type.

Fuel-delivery logistics are a factor in fuel-security risk. As winter progresses, the cumulative use of oil and LNG depletes power plants' inventories, requiring replenishment and heightening the importance of timely fuel deliveries. Refilling oil and LNG tanks at some point over the course of a 90-day winter is not the problem. But when winter storms and cold snaps follow on each other in quick succession, refilling fuel tanks quickly is of paramount importance. Timely replenishment can be challenging, however, because of the difficulty in predicting far enough in advance how much LNG or oil will be needed to ensure trucks and LNG tankers will arrive when needed.

The vagaries of weather, combined with restrictions on how often power plants can run on oil, compound the uncertainties of fuel-delivery logistics. Most power plants in New England are limited to operating on oil no more than 30 days per year. A cold December with limited availability of natural gas could cause a generator to not only deplete its fuel inventory but also reduce the days remaining that it can run on oil – with two months of winter left to go.

The study results highlight significant logistical questions that may have an impact on fuel adequacy for generators. For example, will ocean-going tankers of LNG, a global commodity, arrive in the northeast when needed? Will winter storms prevent oil trucks from delivering fuel to power plants? Will tanker trucks be unavailable because they are delivering oil first to heating customers? Will New England weather deliver a one-two punch of extreme cold followed by a severe storm, leaving more generators with depleted inventories and not enough time to get their tanks refilled, as happened in 2013?[47] And will neighboring power systems deliver the high levels of imports most of these scenarios count on, at a time when their own winter demand is peaking?

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46. Jan Ellen Spiegel, "Canadian fires cause close call for New England power supply," CT Mirror (August 8, 2013), https://ctmirror.org/2013/08/08/canadian-fires-cause-close-call-new-england-power-supply/.

47. ISO New England, "New England grid operated reliably through 2012/2013 winter despite resource performance challenges" (ISO Newswire, March 27, 2013), http://isonewswire.com/updates/2013/3/27/new-england-grid-operated-reliably-through-20122013-winter-d.html.

ISO New England, "Winter Operations Summary: January–February 2013," draft paper (February 28, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb__27_draft_for_discussion.pdf.

Risk Trending in a Negative Direction

Current trends are pushing the New England power system on a path toward greater fuel-security risks. These trends include the increasing retirements of power plants with fuel stored onsite (nuclear, coal and oil); the growth in power plants dependent on natural gas, a fuel that's delivered just in time; growing demand for natural gas from local gas utilities in both New England and the Maritimes, which will likely leave less for power plants; and an increase in renewable resources with variable production.

This fuel-security analysis was conducted to quantify the potential operational impacts of these trends. The wide range of 23 hypothetical scenarios was designed to illustrate the potential outcomes from a variety of future power systems made up of different resource combinations, including more favorable as well as less favorable levels of each variable. The study incorporated expected levels of energy-efficiency measures into its demand forecast and included significant development of behind-the-meter solar, offshore wind, and additional imports.

Only four of the scenarios – including the positive boundary scenario, which is highly unlikely to materialize – had no load shedding and few emergency actions. And the study results clearly show that New England remains extremely vulnerable to the loss of any of the region's key energy facilities.

The reference case, which represents a future power system that could be expected to develop, required hundreds of hours of emergency actions and the depletion of reserves and more than a dozen hours of load shedding. These risks could be offset by additional LNG imports or more renewable energy. However, the addition of large quantities of low-cost renewable resources is expected to lower wholesale energy prices and drive additional non-gas-fired generators to retirement, thus exacerbating fuel-security risks.

On balance, the analysis revealed that fuel-security risks are present in the vast majority of cases, even in scenarios with higher LNG, renewables, and imports.

The wide range of scenarios provides not just clear illustrations of what would happen if the power system evolved as outlined in each scenario, but also allows for conclusions about the outcomes of intermediate levels of each variable.

More Renewables Help, but Don't Eliminate the Risk

Renewable resources can mitigate the region's fuel-security risk, and the study includes scenarios that incorporate all, and in some cases more than, the renewable resources that could result from existing or future clean energy initiatives of several New England states.

The growth of renewable resources, with their low operating costs, is likely to drive greater retirements of more costly, aging coal- and oil-fired power plants. Even when the retirements of these generators occurs in tandem with robust growth of renewable resources, the region's dependence on higher imports of LNG to counteract the loss of stored fuels is not erased.

Another factor is the timing of winter peak demand, which occurs after the sun has set. Solar arrays can help reduce consumption of oil and natural gas for power generation on sunny winter days, preserving more oil and gas to help meet peak demand. But solar PV itself does not help meet the daily winter peak in demand.

Energy from wind farms isn't always available when needed, though offshore wind tends to blow more steadily than onshore wind. Further, developing more onshore wind facilities in northern New England and importing more clean energy from neighboring systems will require significant investment in new transmission infrastructure.

Energy storage can help even out intermittent output from wind and solar resources and support system reliability, but cost-effective, utility-scale advanced energy storage is still being developed.

More Positive Outcomes

A resource mix with higher levels of LNG, imports, and renewables shows less system stress than the reference case. These scenarios, while based on resources dependent on uncontrollable factors – the global LNG market, the coincident winter demands of regions exporting power to New England, and weather – result in fewer hours of emergency actions, depletion of reserves, and load shedding. To achieve these levels of LNG, imports, and renewables, firm contracts for LNG delivery, assurances that electricity imports will be delivered in winter, and aggressive development of renewables, including expansion of the transmission system to import more clean energy from neighboring systems, would be required.

Next Steps

The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018.

A key question to be addressed will be the level of fuel-security risk that the ISO, the region, and its policymakers and regulators are willing to tolerate. As the system operator mandated to maintain a reliable power system, the ISO must conduct its own assessment of the level of risk to reliable operations. A primary consideration will be ISO New England's responsibility, as a regional reliability coordinator, to operate the region's power system in a way that maintains the reliability of not only the region but also the entire Eastern Interconnection.

Discussions about possible solutions to the region's fuel-security risk are also expected to commence in 2018. The ISO will work with stakeholders to determine whether further operational or market design measures will be needed to address the fuel-security risks already confronting the New England power system and that may accelerate in the coming years.

Using the new model developed for this study, the ISO plans to conduct periodic operational assessments to re-evaluate the level of fuel-security risk presented by the resources available at the time. The ISO could also conduct additional analysis based on stakeholder feedback on the study results.

		INPUTS					TOTAL WINTER IMPACT									
							OP 4 Actions			Depletion of 10-Minute Reserves[1]			OP 7 Action: Load Shedding			
							All OP 4 Actions	Actions 6-11								
ROW	**S Reference Case** (i.e., Current Trends) **and Single-Variable Cases**	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)[2]	Imports (MW)	Renewables (MW)[3]	Hours	Hours	Avg. Hourly Power Deficit (MW)[4]	Hours	Avg. Hourly Power Deficit (MW)[4]	Load at Risk (MWh)[5]	Hours	Avg. Hourly Power Deficit (MW)[4]	Unserved Load (MWh)[5]	Days with Load Shedding
1	+ High Boundary	–1,500	1.25	3	3,500	8,000	0	0	0	0	0	0	0	0	0	0
2	More Renewables	–1,500	1.00	2	3,500	8,000	24	6	408	2	765	1,530	0	0	0	0
3	More LNG	–1,500	1.25	2	2,500	6,600	40	9	440	6	545	3,272	0	0	0	0
4	More Dual-Fuel Replenishment	–1,500	1.00	3	2,500	6,600	69	26	319	13	609	7,913	1	696	696	1
5	More Imports	–1,500	1.00	2	3,000	6,600	103	43	404	28	816	22,859	7	290	2,031	4
6	→ **Reference Case (Ref)**	–1,500	1.00	2	2,500	6,600	165	76	419	53	980	51,963	14	743	10,397	6
7	Less Imports	–1,500	1.00	2	2,000	6,600	239	120	427	87	1,039	90,395	33	867	28,608	7
8	Less Dual-Fuel Replenishment	–1,500	1.00	1	2,500	6,600	317	173	410	115	1,079	124,045	46	1,005	46,232	10
9	Less LNG	–1,500	0.75	2	2,500	6,600	355	208	430	153	1,072	164,065	58	1,193	69,179	10
10	More Retirements	–4,500	1.00	2	2,500	6,600	455	316	454	258	1,078	278,135	105	1,431	150,297	16
11	– Low Boundary	–4,500	0.75	1	2,000	6,600	811	692	480	642	1,394	895,145	475	2,080	987,872	31
	C Combination Cases															
12	High Renewables/High Retirements	–3,000	1.00	2	3,500	8,000	84	25	373	17	760	12,918	2	535	1,070	1
13	High LNG/High Renewables/Higher Retirements	–4,000	1.25	2	3,500	8,000	18	4	405	2	500	1,000	0	0	0	0
14	Low LNG/High Renewables/Higher Retirements	–4,000	0.75	2	3,500	8,000	358	200	435	154	1,030	158,552	56	1,009	56,518	12
15	Max Renewables/Max Retirements (Max)	–5,400	1.00	2	3,500	9,500	206	94	408	64	934	59,790	15	907	13,609	6
	O Outage Cases (Modeled on Ref and Max Cases; Assumed More Dual-Fuel Tank Fills)															
16	Distrigas LNG Outage: Ref[6]	–1,500	1.00	3	2,500	6,600	276	114	440	87	961	83,628	24	854	20,496	7
17	Distrigas LNG Outage: Max[6]	–5,400	1.00	3	3,500	9,500	346	181	442	142	971	137,814	49	1,016	49,805	11
18	Canaport LNG Outage: Ref[7]	–1,500	0.65	3	2,500	6,600	270	129	421	90	944	84,973	27	816	22,026	9
19	Canaport LNG Outage: Max[7]	–5,400	0.65	3	3,500	9,500	354	187	424	134	998	133,779	46	844	38,819	11
20	Millstone Nuclear Outage: Ref[8]	–1,500	1.00	3	2,500	6,600	349	166	433	124	1,015	125,852	47	874	41,080	10
21	Millstone Nuclear Outage: Max[8]	–5,400	1.00	3	3,500	9,500	389	243	450	193	1,012	195,358	70	1,147	80,312	12
22	Compressor Outage: Ref[9]	–1,500	1.50	3	2,500	6,600	458	290	468	252	1,231	310,163	138	1,411	194,705	17
23	Compressor Outage: Max[9]	–5,400	1.50	3	3,500	9,500	510	340	448	273	1,107	302,258	121	1,236	149,574	19

1. Once reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding.
2. Count assumed tanks were filled before winter, plus refilled during winter. For example, "2x" counted the initial full tank, plus one refill.
3. Cases with increased renewables also included increased imports to reflect expected additions of clean energy imports from Canada or New York.
4. On average, one megawatt (MW) of electricity can serve about 860 homes in New England, which has about 7.1 million retail customers, encompassing not just residential customers but also commercial and industrial.
5. A megawatt-hour (MWh) of electricity can serve about 860 homes for one hour in New England, on average.
6. Case assumed a disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d the LNG facility can inject into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d).
7. Case assumes the loss of Canaport, the major LNG import facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems.
8. Case assumes the loss of Millstone, one of the region's remaining two nuclear power plants, eliminating 2,100 MW of baseload power.
9. Case assumes the loss of a compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel for the entire winter to generators with a combined capacity of about 7,000 MW.