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 #18-4
October 10, 2018 10:00 a.m. – 4:00 p.m. EST
October 11, 2018 8:30 a.m. – 12:00 p.m. EST
NYPA Niagara Power Project Power Vista Visitor Center
5777 Lewiston Road
Lewiston, New York
Attire: Business Casual

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

Day 1:
Guest Code: 641289945
Password: 3Jd3Tfx@ (35338391 from phones)

Day 2:
Guest Code: 644856258
Password: 8bTEPp@7 (82837717 from phones)

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 NPCC CEAP
5.3 RSC Scope of Work
5.4 RSC Work Plan
5.5 Project 2016-02 CIP Definitions
5.6 RISC Resilience Report

5.7 Project 2018-01 TPL-007 Presentation by Hydro One

5.8 Project 2015-09 SOL Presentation by ISO-NE

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	9/20/18 (I)	
Project 2015-09 Establish and Communicate System Operating Limits	10/17/18 (F)	10/17/18 (I)
Project 2016-02 Modifications to CIP Standards	10/9/18 (I)	10/9/18 (F)
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)	
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-01 Canadian-specific Revisions to TPL-007-2	11/15/18 (F)	11/15/18 (I)
Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	10/22/18 (F)	10/22/18 (I)
Revisions to the NERC Standard Processes Manual	8/9/18 (F)	8/9/18 (A)
Functional Model Advisory Group	9/17/18 (I)	
Standards Efficiency Review	9/26/18 (F)	
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 approval to post ballot if no significant changes are made to the existing redline.

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

Standards Committee (SC) 2019

January 23rd – Call	February 20th – Call	March 20th – Austin TX (Austin Energy)
April 17th – Call	May 22nd – Call	June 26th – Atlanta GA (NERC)
July 24th – Call	August 21st – Call	September 18th – Kansas City MO (KCP&L)
October 23rd – Call	November 20th – Call	December 18th – Atlanta GA (NERC)

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		

Board of Trustees (BOT) 2019 Meeting

February 6-7 - Meeting	May 8-9 - Meeting	August 14-15 - Meeting
November 5-6 - 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 five 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 NPCC Board of Directors Meeting (BOD) 2019

January 30th – ISO-NE Backup Control Center, Windsor CT	March 20th - Call	May 1st – NPCC Office
June 5th – Call	June 26th – NPCC Office	August 7th – Call
September 4th and 5th – Halifax, Nova Scotia	October 30th – Call	December 4th – Montreal, Quebec

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.

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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

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1, 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1, 2	
3.	Ruida Shu	Northeast Power Coordinating Council		1, 2	
4.	Kal Ayoub	FERC	Guest	1, 2	
5.	Howard Gugel	NERC	Guest	1	
6.	Chantal Mazza	Hydro Quebec	2	1, 2	
7	Nicolas Turcotte	Hydro Quebec	1	1	
8.	Michael Golbout	Hydro Quebec	2	1, 2	
9.	Mike Jones	National Grid	3	1, 2	
10.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	Via Phone
11.	Quintin Lee	Eversource Energy	1	1, 2	
12.	Chris Overberg	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1, 2	Via Phone
13.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	
14.	Chris Moir	Ontario Power Generation, Inc.	Guest	1, 2	

15.	Glen Smith	Entergy Services, Inc.	4	1, 2	
16.	Laura Mcleod	New Brunswick Power Corporation	1	1, 2	Via Phone
17.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	
18.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1, 2	
19.	Brian Robinson	Utility Services, Inc.	5	1, 2	
20.	Sean Bodkin	Dominion Resources Services	4	1, 2	Via Phone
21.	Sean Lagan	IESO	Guest	1, 2	Via Phone
22.	Salvatore Spagnolo	NYPA	4	1, 2	Via Phone
23.	Michele Tondalo	The United Illuminating Company	1	1, 2	Via Phone
24.	Jim Grant	NYISO	2	1, 2	
25.	David Kiguel	Independent	7	1, 2	Via Phone
26.	Vijay Puran	New York State Department of Public Service	6	1, 2	Via Phone

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
Chantal Mazza provided a brief safety session and welcomed everyone to Montreal.
Guy Zito called the meeting in order at 10:02AM.

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 minor changes to the RSC meeting agenda.

2.0 RSC Meeting Minutes
Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 6-20-18
Chantal Mazza made the motion for approval.
Payam Farahbakhsh 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.

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

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

4.0 Open Action Items

4.1 Open Action Items List
Action Item: Ruida Shu will send out a word document version of the RSPM to the subgroup.

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 NARUC 2018 Summer Policy Summit
Guy Zito gave a presentation on NARUC and provided summaries on many important topics including the FERC directive on incident reporting.

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
Approval of posting the DER request document and Process document onto NPCC website.
Herb Schrayshuen made the motion for approval.
Jim Grant seconded the motion.
The documents are approved for posting.

5.7 Standards Efficiency Review
Guy Zito reviewed the standard efficiency spreadsheet with the group.

5.8 CAL-ISO SARs on DER
Guy Zito reviewed the CAL-ISO SAR with the RSC group.

5.9 Canadian-specific Revisions to TPL-007-2 Presentation by Hydro One
Payam Farahbakhsh presented TPL-007-2 standard to the RSC group.

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		

Scott Klauminzer called in at 2:30PM to present on Project 2016-02.
He discussed the updates and changes the drafting team made to CIP-002-6, CIP-003-8, CIP-012-1 and Virtualization.
Standard drafting team has worked for over a year on designing virtualization specific language and requirements.
He provided the new Electronic Security Zone and Centralized Management System definition.
The topic is very complex and continues to evolve.
The SDT is moving towards a fuller Cyber Systems approach, modify requirements to be more objective based and technology neutral and backwards compatibility.

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 on the PRC-006-NPCC-2.

PRC-006-NPCC-2 redline is posted on the NPCC website for a 45-day formal comment period.
The main changes to the document are on requirement 4 and requirement 16.
The next drafting team is scheduled to be during the week of October 16-18, 2018.
The goal is to post this for a 30-day pre-ballot and 10-day ballot period by the end of the year.

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

Herb made the motion

Chantal seconded the motion

10.0 RSC Member Items of Interest

10.1 RSC Roster

Ruida Shu reviewed the RSC roster with the RSC group.

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

The meeting is adjourned at 10:12AM on August 23, 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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- 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.

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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 Louis 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: 9/2/2018 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: 9/2/2018

	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 Procedur	N/A	Procedure for Operations Planning Model Data Exchange	TFCO	New	TFCO Proposing New Document	Pending TFCO Approval

NPCC Directory Criteria Clarifications

Revised: 9/2/2018 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

9/2/2018

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.

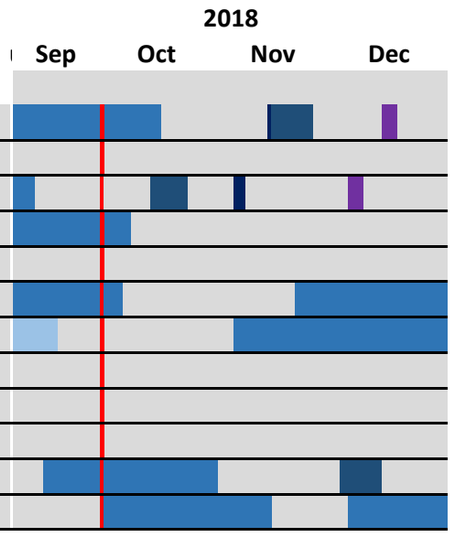
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SUMMARY
Updated: 10/2/2018
Tutorial Video (11 min)
Click here to report errors or issues

Nom-SAR/D QR Posting-SAR or PR Post

HOME

U	Project (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
G	2015-09 - Establish and Communicate System Operating	CIP-014-3, FAC-003-5, FAC-013	(228)	Current
G	2015-09 - Establish and Communicate System Operating	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	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	2017-03 - Periodic Review of FAC-008-3 Standard	PR Recommendations		N/A
G	2017-04 - Periodic Review of Interchange Scheduling and	PR Recommendations		N/A
G	2017-05 - Project 2017-05 NUC-001-3 Periodic Review	PR of NUC-001-3 Standard		N/A
G	2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE		Proposed
G	2018-01 - Canadian-specific Revisions to TPL-007-2	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	Posted	Currently posted for formal through October 17, 2018 (extended from the 9th). 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, PRC-026 and the retirement of FAC-010	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, PRC-026 and the retirement of FAC-010	10/2/2018
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	10/2/2018
2015-10	Single Points of Failure TPL-001	Working to Final Ballot	The project was posted through September 14, 2018. The standard passed with a weighted segment value of 69.07% and the Implementation Plan passed at 73.27%. The non-binding pool of VRFs/VSLs also passed. The drafting team is meeting October 2-4 and will determine next steps, which could be a final ballot.	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	10/2/2018
2016-02	Modifications to CIP Standards	Posted	The standard is current posted for formal comment and initial ballot through October 9, 2018. The drafting team will meet to respond to comments following the ballot and to determine next steps.	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, Ash Mayfield, and Kirk Rosener	CIP-002-5.1a	9/24/2018
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	9/24/2018
2016-02	Modifications to CIP Standards	Posted	The CIP-003 standard is posted for comment and initial ballot through October 9, 2018. The drafting team will meet to respond to comments following the ballot and to determine next steps.	FERC Order No. 843 Malicious Code Example Directive (CIP-003-8)	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	9/24/2018
2017-01	Modifications to BAL-003-1.1	Posted	The standard was informally posted through September 20, 2018. The SDT met the week of September 24, 2018 at SPP in Little Rock, AR to review comments.	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	10/2/2018
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.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Al McMeekin	Mark Pratt	FAC-008-3	10/2/2018
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.	PR 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	10/2/2018
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.	PR 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	10/2/2018
2017-07	Stds Alignment with Registration	Working to Comment Posting	The SDT will collaborate with SER team for the NUC-001-3 Reliability Standard and have the SER team address the change. The SDT will likely go forward with posting PRC-005 and PRC-006 in October along with other standards to change Planning Authority to Planning Coordinator. The project is anticipated going to the SC in October to appoint drafting team members and to authorize initial comment and ballot. The SDT also submitted their baseline project schedule and the PMOS accepted their baseline proposal.	Standards with PSE, IA, or LSE		Footnote 9, Low	N/A	N/A	N/A	N/A	Laura Anderson	Mike Brytowski	Standards with PSE, IA, or LSE	9/24/2018
2018-01	Canadian-specific Revisions to TPL-007-2	Posted	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot.	TPL-007-3	N/A	Footnote 10, Medium	N/A	N/A	N/A	N/A	Mat Bunch	Charles Yeung	TPL-007-2	10/2/2018

2018-02	Modifications to CIP-008 Cyber Security Incident Reporting	Working to Comment Posting	The SC appointed the SAR drafting team at its September 13, 2018 meeting. The team will meet at NERC in Atlanta on September 24, 2018.	CIP-008-6	1/19/2019	Footnote 10, High	N/A	Order No. 848 (1 Directive, 4 elements)	N/A	N/A	Alison Oswald	Colby Bellville & Amy Casuscelli	CIP-008-5	10/2/2018

Project	**Standards Efficiency Review**	**Home**
Project Name	Standards Efficiency Review	
Status	SAR	
Comments	The Standards Authorization Request was posted through September 26, 2018. Drafting team nominations were posted through September 17, 2018.	

Deliverable	Retirement of various requirements
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	N/A, not priorized in the RSDP
Operations Planning Subteam	Amy Casuscelli & Charles Yeung
Real-time Operations Subteam	Mike Brytowski
Long-term Planning Subteam	Linda Lynch
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Chris Larson
Primary PMOS Liaison(s)	Mark Pratt & Michael Brytowski
Affected Standards	See SAR (too many to list)
Last Updated	10/2/2018

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	Index
Nominations - SAR / PR	***10/3/2018***	***10/17/2018***	10/10/2018	10/24/2018	7			1
Nominations - DT	11/7/2018	11/21/2018	11/14/2018	11/28/2018	7			2
QR - Quality Review	12/12/2018	12/26/2018	12/19/2018	1/2/2019	7			3
SP1 - SAR/PR/WP Posting 1	1/16/2019	2/15/2019	1/23/2019	2/22/2019	7			4
SP2 - SAR/PR/WP Posting 2	3/8/2019	4/7/2019	3/15/2019	4/14/2019	7			5
CP1 - Comment Period 1	4/28/2019	5/28/2019	5/5/2019	6/4/2019	7			6
CP2 - Comment Period 2	6/18/2019	7/18/2019	6/25/2019	7/25/2019	7			7
CIB - Com/Ballot 1 (Initial)	8/8/2019	9/22/2019	8/15/2019	9/29/2019	7			8
CAB - Com/Add Ballot 2	10/13/2019	11/27/2019	10/20/2019	12/4/2019	7			9
CAB - Com/Add Ballot 3	12/18/2019	2/1/2020	12/25/2019	2/8/2020	7			10
CAB - Com/Add Ballot 4	2/22/2020	4/7/2020	2/29/2020	4/14/2020	7			11
CAB - Com/Add Ballot 5	4/28/2020	6/12/2020	5/5/2020	6/19/2020	7			12
FB - Final Ballot	7/3/2020	7/13/2020	7/10/2020	7/20/2020	7			13
PTB - Present to BOT	8/3/2020	8/5/2020	8/10/2020	8/12/2020	7			14
Filing - Filing with Regulators	8/26/2020	8/29/2020	9/2/2020	9/5/2020	7			15
PT - Post Approval Training	9/19/2020	9/22/2020	9/26/2020	9/29/2020	7			16

PTS Change Control

Reason for Update	Date	Notes

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Posted
Comments	Currently posted for formal through October 17, 2018 (extended from the 9th). 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, PRC-026 and the retirement of FAC-010
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, PRC-026 and the retirement of FAC-010
Last Updated	10/2/2018

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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***	***10/17/2018***					not in original baseline
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/16/2018	11/26/2018	4/2/2018	4/12/2018	(228)		
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	10/2/2018	

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	Working to Final Ballot
Comments	The project was posted through September 14, 2018. The standard passed with a weighted segment value of 69.07% and the Implementation Plan passed at 73.27%. The non-binding pool of VRFs/VSLs also passed. The drafting team is meeting October 2-4 and will determine next steps, which could be a final ballot.
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	10/2/2018

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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	Posted
Comments	The standard is current posted for formal comment and initial ballot through October 9, 2018. The drafting team will meet to respond to comments following the ballot and to determine next steps.

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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, Ash Mayfield, and Kirk Rosener
Affected Standards	CIP-002-5.1a
Last Updated	9/24/2018

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***	***10/9/2018***	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	9/24/2018	

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	9/13/2018	PMOS accepted the baseline following appointment of additional members in July 2018.
Delay	9/1/2018	Project delayed from August 2018 to January 2019 (tentatively) for 2018-02, CIP-008 to finish.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Posted	
Comments	The CIP-003 standard is posted for comment and initial ballot through October 9, 2018. The drafting team will meet to respond to comments following the ballot and to determine next steps.	
Deliverable	FERC Order No. 843 Malicious Code Example Directive (CIP-003-8)	
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	9/24/2018	

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)	***8/23/2018***	***10/9/2018***	***8/23/2018***	***10/7/2018***			
CAB - Com/Add Ballot 2	11/22/2018	1/6/2019	11/22/2018	1/6/2019			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/4/2019	1/25/2019	2/4/2019			
PTB - Present to BOT	2/6/2019	2/8/2019	2/6/2019	2/8/2019			
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.
Accept Baseline	TBD	PMOS Accepted the baseline provided by the SDT.

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1.1	
Status	Posted	
Comments	The standard was informally posted through September 20, 2018. The SDT met the week of September 24, 2018 at SPP in Little Rock, AR to review comments.	
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	10/2/2018	

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	9/6/2018	9/20/2018					Unscheduled posting
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	**2017-03**	**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	PR 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	10/2/2018	

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	PR 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	10/2/2018	

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	PR 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	10/2/2018	

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	**2017-07**	**Home**
Project Name	Stds Alignment with Registration	
Status	Working to Comment Posting	
Comments	The SDT will collaborate with SER team for the NUC-001-3 Reliability Standard and have the SER team address the change. The SDT will likely go forward with posting PRC-005 and PRC-006 in October along with other standards to change Planning Authority to Planning Coordinator. The project is anticipated going to the SC in October to appoint drafting team members and to authorize initial comment and ballot. The SDT also submitted their baseline project schedule and the PMOS accepted their baseline proposal.	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low	
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	Mike Brytowski	
Affected Standards	Standards with PSE, IA, or LSE	
Last Updated	9/24/2018	

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	2/5/2019	2/8/2019	2/5/2019	2/8/2019			
Filing - Filing with Regulators	3/7/2019	3/10/2019	3/7/2019	3/10/2019			
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 as presented to the members.

Project	**2018-01**	**Home**
Project Name	Canadian-specific Revisions to TPL-007-2	
Status	Posted	
Comments	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot.	
Deliverable	TPL-007-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 10, 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	Mat Bunch	
PMOS Liaison	Charles Yeung	
Affected Standards	TPL-007-2	
Last Updated	10/2/2018	

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)	***10/2/2018***	***11/15/2018***	10/5/2018	11/19/2018	3		
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	2/7/2019	5/5/2019	2/7/2019	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	PMOS accepted the baseline schedule as presented to the members.

Project	**2018-02**	**Home**
Project Name	Modifications to CIP-008 Cyber Security Incident Reporting	
Status	Working to Comment Posting The SC appointed the SAR drafting team at its September 13, 2018 meeting. The team will meet at NERC in Atlanta on September 24, 2018.	
Comments		

Deliverable	CIP-008-6
Deadline	1/19/2019
Priority in RSDP, click to see applicable Footnote	Footnote 10, 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	Colby Bellville & Amy Casuscelli
Affected Standards	CIP-008-5
Last Updated	10/2/2018

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 Colby Belleville and Amy Casuscelli 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
Note 10	2019-2021 RSDP (Draft)

RSC Meeting #18-4, 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

October 1–7, 2018

INSIDE THIS EDITION

Active Standards Postings | Other Active Comment Periods | Standards News | General Compliance and Enforcement 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-002-6 and CIP-003-8	Initial Ballots and Non-binding Polls	09/28/18	10/09/18
Project 2015-09 – Establish and Communicate System Operating Limits	Initial Ballots, Additional Ballots, and Non-binding Polls	10/08/18	10/17/18
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**

Project 2016-02 – Modifications to CIP Standards | CIP-002-6 and CIP-003-8	Comment Period	08/23/18	10/09/18
Project 2015-09 – Establish and Communicate System Operating Limits	Comment Period	08/24/18	10/17/18

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Proposed Revisions to the NERC Rules of Procedure: NERC is proposing revisions to Sections 600 (Personnel Certification) and 900 (Training and Education) of its currently effective Rules of Procedure (ROP). The purpose of these revisions is in response to the Federal Energy Regulatory Commission's directives issued in the July 19, 2018 *Order Approving in Part and Denying in Part Revisions to North American Electric Reliability Corporation Rules of Procedure and Requiring Compliance Filing*, 164 FERC ¶ 61,023 (2018) to (i) submit a compliance within 120 days restoring ROP Sections 603, 604, and 605, and (ii) correct typographical errors in proposed Sections 600 and 900. NERC proposes to request that these revisions become effective immediately after filing with FERC. NERC requests comments on the proposed revisions to the NERC Rules of Procedure. The 45-day comment period begins August 27, 2018 and ends October 11, 2018.	Submit comments to ROPcomments@nerc.net.	08/27/18	10/11/18

A redlined version of NERC Rules of Procedure, Sections 600 and Section 900 showing the proposed revisions are available on the NERC Rules of Procedure page.			

STANDARDS NEWS

NEW Nomination Period Open for Project Management and Oversight Subcommittee

Nominations are being sought for Project Management and Oversight Subcommittee (PMOS) members through October 9, 2018.

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)

The PMOS is seeking to fill one to three positions. Desirable qualifications include candidates knowledgeable of the Standard Processes Manual and have a broad historical knowledge of Reliability Standards. The PMOS works with NERC staff to support industry subject matter experts in all aspects of standard development. Consider reviewing the PMOS Scope for additional information. This includes advising and supporting standard drafting teams, enhanced periodic review teams, and special projects to achieve standard goals specified in the Reliability Standards Development Plan. The PMOS reports to the Standards Committee (SC).

The PMOS maintains and updates a Project Tracking Spreadsheet which shows the expected and actual project milestones for each project. In addition, the PMOS works with NERC staff in maintaining a deliberate pace of development, while staggering posting periods of projects to ensure there is no industry burden during comment periods. Each project has an assigned PMOS liaison that maintains active engagement with their assigned standard development project team(s) and developer(s), as well as, reports updates during PMOS meetings and conference calls to other subcommittee members and SC leadership.

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 in the Related Files section of the PMOS web page. By submitting a nomination form, you are indicating your willingness and agreement to participate in PMOS meetings. If selected, members are expected to attend face-to-face PMOS meetings, as well as participate in all the PMOS meetings held via conference calls. The time commitment for this effort is one face-to-face

meeting per quarter held prior to the SC meeting with four to eight conference calls scheduled as needed. SC members and others interested in NERC Reliability Standards are encouraged to submit nominations for representatives on the PMOS.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Two Reliability Standard Audit Worksheets Posted

Two Reliability Standard Audit Worksheets (RSAWs) are now available on the RSAW page of NERC's website under the heading "Current RSAWs for Use:"

- EOP-004-4 (Event Reporting) applies to many entities and the effective date of the Standard is 4/1/2019. EOP-004-4 will replace EOP-004-3.
- EOP-006-3 (System Restoration Coordination) applies only to Reliability Coordinators, and the effective date of the Standard is 4/1/2019. EOP-006-3 replaces EOP-006-2.
- MOD-026-1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions) applies to Generator Owners and Transmission Planners has an errata change, changing a reference to a verification date to a transmittal date in order to align with the Standard.

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

NEW Issues and Recommendations Tracking Spreadsheet Updated

On September 28, 2018, the Issues and Recommendations Tracking spreadsheet on the ERO Enterprise Program Alignment page was updated.

NEW Newly Effective Standard

On October 1, 2018, BAL-004-WECC-3 – Automatic Time Error Correction became effective.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

Please refer to the U.S. Effective Dates page for more detail on the standards listed below.

U.S. Effective Dates for Reliability Standards	
U.S. Effective Date	**Standard(s)**
October 1, 2018 EFFECTIVE THIS WEEK	BAL-004-WECC-3 – Automatic Time Error Correction
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

NEW NERC Filings

On September 26, 2018, NERC, Midwest Reliability Organization (MRO), and Reliability First Corporation (RF) filed with FERC a joint petition seeking approval for the proposed registration transfer request of Wisconsin Public Service Corporation and Upper Michigan Energy Resources Corporation from the MRO footprint to the RF footprint. At this time, the joint petition remains un-docketed. NERC will update the docket number on its website when it is assigned.

On September 28, 2018, NERC submitted to FERC an informational filing regarding BAL-001-2 in Docket No. RM14-10-000.

On September 28, 2018, NERC also filed with FERC an annual report on Wide-Area Analysis of Technical Feasibility Exceptions in Docket No. RM10-1-000 and RM13-3-000.

NERC's 2018 filings to FERC are available here.

NEW FERC Issuances

On August 17, 2018, NERC filed with FERC a petition for approval of proposed Reliability Standard BAL-002-3 – Disturbance Control Standard — Contingency Reserve for Recovery from a Balancing Contingency Event. On September 25, FERC issued a delegated letter order approving NERC's August petition filing in Docket No. RD18-7-000.

On June 4, 2018, NERC filed with FERC a petition for approval of amendments to its Bylaws. On September 25, FERC issued a letter order accepting the revisions to the NERC Bylaws in Docket No. RR18-7-000.

FERC's 2018 issuances 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

- **NEW** Project 2015-09 – Establish and Communicate System Operating Limits Webinar – 2:00–4:00 p.m. Eastern, October 4, 2018 | Register

Standing Committee Meetings and Conference Calls

- **NEW** Member Representatives Committee Pre-Meeting Conference Call and Informational Webinar – 11:00 a.m.–12:30 p.m. Eastern, October 10, 2018 | Register
- Board of Trustees Committees, Member Representatives Committee, Board of Trustees Meetings – November 6–7, 2018, Atlanta | Registration and Hotel Information

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.

- Project 2015-10 – Single Points of Failure Standard Drafting Team Meeting – October 2–4, 2018, Austin, TX | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards Drafting Team Meeting – October 23–25, 2018, Atlanta| 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 submit a ticket through the Help Desk. Select the "NERC Email Distribution List" option under the "Applications" menu. In the Description Box, please specify which lists you would like your email address to be added to or note which announcements you would like to receive. This bulletin is distributed to several lists, including the Standards distro list (Standards-specific announcements) and the NERC-info distro list (most NERC announcements).

201~~9~~8 Scope of Work
for the
Regional Standards Committee (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors (BOD), is charged with:

(a) Managing the NPCC Regional Standards Development Process.
(b) Managing the NPCC Directory and Criteria Development and Review Process.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Reliability Standards Development Processes.
(d) Reviewing FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to Reliability Standards, by providing a forum for developing consensus.~~.~~
(e) Reviewing each new and revised NERC Reliability Standard Audit Worksheet (RSAW) and submitting comments to NERC as necessary.
(f) Providing consolidated NPCC Regional review and comments to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure as they relate to Standards Development.
(g) Determining the need for and development of NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Directories and Criteria, and/or interpretations and clarifications thereof.
(h) In coordination with the Compliance Committee, address issues identified through the NPCC Regional Feedback Mechanism to continually improve standards and NERC documents such as Guidelines and other technical material.
(i) Providing a forum for sharing viewpoints and opinions with the goal of achieving consensus regarding reliability attributes of various forms of industry standards, guidance and/or regulations.

Subsequent to receiving comments from NPCC stakeholders, the RSC will be responsible for submitting those consensus Regional comments to ~~-~~NERC.

The RSC is an open and balanced committee inclusive of all stakeholders that provide for, or are materially impacted by, the reliability of the Bulk Electric System. The RSC meetings are open to all stakeholders who want to participate and meeting materials will be publicly posted on the NPCC Website.

Decisions of the NPCC RSC will be adopted under a sector based voting structure as

described in the NPCC Amended and Restated Bylaws.

The RSC will coordinate its work through the NPCC Standards Program Area Staff which will administer actions as denoted in the NPCC Regional Standard Processes Manual and coordinate the review and submission of all standards related comments pursuant to the NERC Standards Development Processes Manual and the NERC Rules of Procedure.

The RSC will be chaired and assisted by NPCC Standards Program Area Staff along with co-vice chairs elected by the RSC from among the members of the RSC at the time the vote is taken. Chair and Co-Vice Chair appointments will be submitted to the NPCC Board of Directors for approval. The Co-Vice chairs will serve a term of two years. The Vice-Chair term may be extended through a motion and subsequent vote by the committee in accordance with the NPCC Amended and Restated Bylaws. An RSC Executive Committee will assist in management of the RSC and will be comprised of the Chair, the Co-Vice Chairs and two elected RSC members (the two elected RSC members will be comprised of a Canadian representative and a U.S. representative). Additionally, the two RSC members elected to the RSC Executive Committee by the RSC membership will serve for a two-year term.

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review the nominations which will include contact information and qualifications to serve on the committee. Appointments to the RSC will be approved by the RSC Executive Committee. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be represented on the RSC.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC by NPCC Standards Program Area Staff. All associated scopes or charters developed, will be approved by the RSC in accordance with the most recent approved NPCC Amended and Restated Bylaws.

Each RSC Member is accountable to the members of the RSC and the NPCC Board of Directors for carrying out their responsibilities in accordance with this document.

RSC Members are to represent their companies and sectors and will also work to resolve differences with a principal goal of maintaining or improving power system reliability.

RSC Members should base their decisions on what is best for power system reliability and must consider not only what is best for their company but also what is in the best interest of the broader industry and Bulk Electric System reliability.

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC Member make a commitment to be present. A determination to recommend removal of a member shall be considered by the NPCC RSC Executive Committee if a member is excessively absent and provides no proxy for regularly scheduled meetings.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the standards process for the development of ERO

Regional Standards, Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), definitions, variances, interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual and the NPCC Amended and Restated Bylaws pertaining to quorum and voting rules. The RSC is responsible for ensuring the quality of all Standards-related materials.

The RSC will be available to advise the NPCC BOD on Regional Standard related matters.

B. NPCC Directory and Criteria Process Responsibilities

The RSC provides oversight for the development of NPCC Directories and the criteria within each document. The RSC will provide guidance to all NPCC Committees, Task Forces and Working Groups regarding the development of NPCC documents including Directories, Criteria Procedures and Guidelines.

The RSC will be available to advise the NPCC BOD on Directory and Criteria related matters.

C. NERC Reliability Standards Responsibilities

The RSC will:

- Provide a forum for NPCC review, coordination and submission of NPCC comments to existing or proposed NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit and provide Regional comments on Standard Authorization Requests (SARs) and their respective Reliability Standards in accordance with the NERC Standard Development Processes Manual.
- Provide a forum for NPCC to participate in, and be kept aware of emerging risks from the NERC Reliability Issues Steering Committee (RISC)
- Provide a forum for NPCC to participate, solicit and provide Regional comments to the Periodic Review Process for standards.
- Identify prospective reliability issues associated with new or revised NERC Reliability Standards and their potential impact on the NPCC Region, (i.e., Regional differences).
- Propose solutions or guide the development of the NERC Reliability Standards through effective and timely comments and soliciting NPCC participation on the SAR, Periodic Review and Reliability Standard Drafting Teams.
- Develop and maintain a web-based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wide range of participants across the NPCC membership during the Standard commenting process in order to achieve broad regional consensus. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Follow up on proposed and adopted changes to the NERC Standard Development Processes Manual and Rules of Procedure as they apply to Reliability Standards, and provide NPCC members with basic information (or assistance with the NERC Website) for a common understanding of the processes.
- Coordinate the activities of NPCC members on Standard Drafting Teams, and encourage NPCC representation on all Standard Drafting Teams.
- Coordinate with the CC any NPCC input to CMEP Implementation Guidance documents in accordance with the CC process for submitting implementation guidance to NERC.
- Participate NERC Standards Efficiency Review and coordinate Regional participation.

D. FERC Activities Affecting Standards

The RSC will review FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) relating to ERO and Regional Reliability Standards. The RSC will discuss, develop regional consensus positions, and if necessary, develop recommended comments for consideration by the NPCC Board of Directors to FERC on behalf of NPCC.

When requested, participate in technical conferences hosted by NERC, FERC or other Regions on topics of importance to power system reliability.

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 201~~9~~8-202~~0~~019

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 201~~9~~8 - 202~~0~~019 will be consistent with the NPCC 201~~9~~8 and 202~~0~~019 Business Plans and Budgets, Organizational and Strategic Goals, both approved and in draft, and will also continue to be supportive of the ongoing periodic reviews, standard development and standards efficiency review activities. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals.

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

To carry out its standards related responsibilities defined in the NPCC RSC Scope of Work, the RSC will perform the following activities:

1. Monitor NERC's Reliability Issues Steering Committee (RISC) risk profiles and other reliability related issues and priorities for potential incorporation into NERC standards, for removal from standards or for potential incorporation into guidelines or other non-standards-based solutions. Provide and coordinate NPCC's input into those decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active regional participation in the Periodic Review Standing Review Team.
3. Review and support the ERO standards efficiency initiative and ongoing standards development work which is defined to be a core set of results-based standards achieving an adequate level of reliability. Provide ongoing input to the Periodic Review Template used to determine the efficacy of standards.
4. Continue to provide input for consideration of costs in NERC's Standards Development program.
5. Oversee, and participate in the regional standards development process and base any development, revision or retirement of NPCC Regional Reliability Standards on the reliability related needs of the Region or continent-wide ERO standards such as the ongoing revision of NPCC PRC-006-NPCC-1 Underfrequency Load Shedding
6. Engage in the NERC Compliance Guidance Policy process. Support the inputs through the NPCC Compliance Committee by providing technical and policy related opinions as necessary.
7. Coordinate NPCC Regional Standards development activity with NERC Standards development activity to ensure resources are available for efficient and effective standards development and implementation.
8. Coordinate NPCC participation in reviews and revisions of NERC Standards when addressing reliability directives from FERC's Orders and any Provincial regulatory directives.
9. Participate in standards development activities related to Resilience.
10. Address emerging issues FERC has identified with the NPCC Regional Standard Processes to promote consistency and support of the ERO Enterprise Alignment.
11. Conduct thorough reviews of all NERC Standards being developed or revised and coordinate timely comments within the NPCC Region based on reliability needs, results-based requirements, and Periodic Reviews.
12. Develop and submit Standard Authorization Requests (SARs) for revisions when necessary to improve Standards and address reliability related issues for approved or draft Standards utilizing input from the NPCC Regional Feedback Mechanism to improve the quality and efficacy of standards.
13. Develop ballot recommendations or "issues statements" for RSC members for all NERC Standards

under development.

14. Review and develop ballot recommendations for all NERC formal interpretations to Standards.
15. Provide guidance to NPCC Regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
16. Respond to FERC and Provincial filings and interrogatories on issues related to regional Standards.
17. Serve as a liaison for the Northeast Region to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
18. Participate in the proceedings of various NERC groups to contribute to the continual improvement of NERC Standards and processes. These groups include but are not limited to:
    a. NERC Standards Committee (SC)
    b. NERC Standards Committee Process Subcommittee (SCPS)
    c. NERC Project Management Oversight Subcommittee (PMOS)
    d. NERC Functional Model Advisory Group (FMAG)
    e. NERC SAR and Standards Drafting Teams (SDTs)
    f. NERC Reliability Issues Steering Committee (RISC)
    g. NERC Standards Efficiency Review (SER) Teams
19. Manage the development and revision of the Regional Reliability Directories including Criteria clarifications as necessary and review all NPCC Criteria to ensure consistency with NERC or regional Reliability Standards.
20. Promote the NPCC Criteria as augmenting and providing specificity to NERC standards requirements or addressing reliability risk issues not addressed in existing NERC standards. Coordinate efforts with the NPCC Compliance Committee to facilitate further development of the NPCC Criteria Compliance Enforcement Program (CCEP) via Phase 2 of the Directory Project which was initiated to reformat the criteria section of each Directory into measurable NERC-style requirements.
21. Develop proposed standards and standard clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee, RSC or as identified through the NPCC Regional Feedback Mechanism.
22. Work with the NPCC CC to develop the necessary compliance elements of the Regional Standards, for example, Violation Severity Levels (VSLs).
23. Implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, as needed, and promote and participate in the NERC cost effectiveness approach to the ERO draft continent-wide Standards.
24. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances, and provide input to support development of a NPCC consensus opinion.
25. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
26. Educate and notify NPCC Region stakeholders and regulators about issues related to Standards development.
27. Participate in two scheduled NPCC Compliance and Standards Workshops
28. Participate in the revision and redrafting of the NERC Rules and Procedures and other documents related to standards development such as, but not limited to:
    a. The NERC Functional Model Working Group (FMWG)
    b. The NERC Standards Committee (SC)
    c. The NERC Standards Committee Process Subcommittee (SCPS)
29. Coordinate implementation of the NERC Standards development processes and NPCC Regional Standard processes and recommend revisions as necessary.

NPCC Regional Standards Committee Program Responsibilities (related to Directory Criteria)

1. Coordinate Directory Development activities with the regulatory authorities in the U.S. and applicable Provincial authorities.

2. Identify the need for new or modified NPCC Directories and the Criteria, Guidelines and Procedures within pursuant to Section 313 of the NERC ROP responsibilities
3. Oversee a broad review for the development, modification, or retirement of Directories in accordance with the NPCC Directory Development and Revision Manual
4. Coordinate Directory Criteria requirements with Regional and NERC Standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.
5. Develop filings for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent regional criteria for New York State.
6. Develop filings of Directories as required with the Provincial authorities as per the various Memorandums of Understanding.
7. Communications
    a. Announce development activities pertaining to the NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the Bulk Power System in the Region to be aware of and apply the NPCC regionally-specific criteria.
    b. Identify future Regional Standard development or retirement opportunities by developing a set of Regional Reliability Directories incorporating the ERO Reliability Standards, Regional Standards and Regionally-specific more stringent Criteria.

The activities listed in this work plan are based on the current planned execution of the NERC Reliability Standards Development Plan (RSDP), proposed strategic direction of the NPCC BOD and NERC BOT as well as additional Directives from the FERC Orders. Changes to these programs, the NERC RSDP, the NERC Rules of Procedure, or the NPCC Standards or Directory processes may necessitate changes to listed activities, including revised scheduling of the activities, removal of certain activities, and/or the addition of activities. If significant changes occur during the course of the year, the RSC Work Plan will be revised in advance of the NPCC Board of Director's annual review and will be forwarded to the NPCC Board of Directors for approval.

Definitions for Consideration of Modification: Project 2016-02

Cyber Asset (CA) - Retired

BES Cyber Asset (BCA) – Retired

BES Cyber System (BCS) – 4 options. Present to the team on Thursday. Gather feedback and work on at next meeting. Feedback from in-person meeting: Data.

Electronic Access Control or Monitoring Systems (EACMS) – Retired. Proposed EACS and EAMS. Why separate: EACMS is overloaded within the definition.

Electronic Access Control Systems (EACS)

Electronic Access Monitoring Systems (EAMS)

Electronic Security Perimeter (ESP) – Retired

Virtual Programmable Asset (VPA)

Physical Access Control Systems (PACS)

Updated from PCA to Protected Cyber Systems (PCS): define logical isolation? If became a part of the adjacent system, would it go away? If you have more systems, then the question would be which system would it go with? Dual systems. Is Physical isolation, logical isolation? Consider explaining logically within the requirement. Hanging out on the network.

Associated

Electronic Access Point (EAP) – Retired

Intermediate System (IS)

Centralized Management System (CMS)

Management Interface

External Routable Connectivity (ERC)

Interactive Remote Access (IRA)

Cyber Security Incident

Definitions for Consideration of Modification: Project 2016-02

The Definition ad hoc group has reviewed the NERC Glossary of Terms. We have not reviewed the standards.

Definitions for Consideration of Modification: Project 2016-02

NERC Glossary Term	Currently Approved Definition	CIP SDT Proposed Modified Definition
Cyber Asset (CA)	Programmable electronic devices, including the hardware, software, and data in those devices.	Keeping CA for very few places the CA term is needed. Programmable electronic devices, including the physical or virtual hardware, software, and data in those devices.
BES Cyber Asset (BCA)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse	RETIRED
Transient Cyber Asset	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or	~~A Cyber Asset~~ Programmable electronic devices, including the hardware, software, and data in those devices that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber ~~Asset~~ System (~~PCA~~PCS) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber System ~~BES Cyber Asset,~~ • network within a~~n~~ BES Cyber System logical isolation ~~Electronic Security Perimeter (ESP)~~ containing high or medium impact BES Cyber Systems, or • ~~PCA~~ PCS associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber ~~Assets~~ Systems used for data transfer, vulnerability

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Commented [JM1]: Def. Ad hoc group is still going towards retiring CA. Need feedback from other ad hoc groups on if the CA can easily be replaced with "systems" or something else as modifications are being made.

Commented [JM2]: Potential option if we keep CA: A physical or virtual electronic programmable device that…

Commented [JM3]: Explain virtual hardware in guidance. Allows virtual hardware. CA is used for both physical and virtual things. (break up the network presence from the physical presence.

Commented [JM4]: Consider moving hardware to other relevant definitions or requirements (CIP-006, CIP-011)

Commented [JM5]: How is virtual handled in this case and the BCS?

Commented [JM6]: If PCS is not needed, then this can be deleted.

Commented [JM7]: Options:
Maybe keep PCS and explain in the IG of how one could have these things.

Maybe an exemption

Maybe make PCS a super set

See CIP-004, CIP-008, CIP-009

Commented [JM8]: Need to avoid this statement in general.

Can likely delete this bullet. This is basically the applicability column for the TCA.

Commented [JM9]: Associated with note above. If PCS goes away, then this bullet can be deleted.

	• PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.	assessment, maintenance, or troubleshooting purposes.
BES Cyber System (BCS)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.	Any combination of hardware, software, and data ~~logically grouped,~~ that performs one or more reliability tasks, that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more BES Facilities. 1. Including systems not logically isolated from high and medium BES Cyber Systems, and 2. Including redundant systems ~~3. excluding those only connected serially to the BES Cyber Systems.~~
Electronic Access Control or Monitoring Systems (EACMS)	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.	RETIRED – Proposed Develop EAMS and EACS
Physical Access Control Systems (PACS)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.	~~Cyber Assets~~ Systems that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Protected Cyber Asset (PCA)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest	~~RETIRED/Option 3.~~ Based on vote made by team, the definitions group is to consider option 1 and option 2 now. ~~One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.~~

Commented [JM10]: Is "and" the correct word? Does this mean combination or all?

Hardware was added based on replacing CA term.

Commented [JM11]: Adversely Impact glossary of term: add words from the def. to replace lowercase adversely impact or leave lowercased.

Maybe consider adding additional language to explain what the team means by adverse impact. Helping not use Adverse Reliability Impact term and creating too high of a bar.

Ad hoc group is reconsidering adding the term Adverse Reliability Impact. The group went through the defined term and did not see how it would be seen as too broad of a term to explain adversely impact.

NERC is charged to maintain Adequate level of reliability.

What does this mean? There has been disagreement between auditors and entities.

What are the standards trying to do? Trying to maintain a state of reliability. Can the standard still do what it was intended to do.

Commented [JM12]: Do we mean adverse impact or things that are within 15 minutes…? Adversely impact is a …

Commented [JM13]: How is virtual handled here?

Commented [JM14]: Do we need to be more detailed…virtual hardware? …

Commented [JM15]: This is an implementation question instead of a definitional issue.

Commented [JM16]: Replacing PCA/PCS. …

Commented [JM17]: This needs to be deleted based on vote SDT had. Definitions team will need to consider another place this needs to be put.

Commented [JM18]: Additional scoping info…. Move up and will not need a bulleted list at this time.

Formatted: Indent: Left: 0.5", No bullets or

Commented [JM19]: Revert if we keep CA definition.

Commented [JM20]: Consider this or. Taking the "m" out of ECAMS…if a system only logs access…should that be a PACS? (e.g. sending over a SIEM…does that make it a PAC …

Commented [JM21]: If we retired this, it would not allow the team to move forward with being backwards compatible. …

Commented [JM22]: Add CA to November 1 webinar.

	rated BES Cyber System in the same ESP.	Updated term to: Protected Cyber System (PCS) **Option 1:** Systems not logically isolated from BES Cyber Systems, excluding those only connected serially to the BES Cyber Systems. (Negative Example) **Option 2:** Systems that are able to communicate with the BCS without going through access permissions. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System accessible without going through access permissions. (Positive Example) Option 3: Retire term and incorporate into the BCS ~~by adding the~~
Electronic Access Point (EAP)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.	RETIRED
Centralized Management System (CMS)	NEW TERM	A logically centralized system used for administration or configuration of one or more cyber system(s). Transient Cyber Assets and Intermediate Systems are not CMS.
Electronic Access Control System (EACS)	NEW TERM	Systems that perform electronic access control for BES Cyber Systems. Intermediate Systems are a type of EACS.
Electronic Access Monitoring Systems (EAMS)	NEW TERM	Systems that perform electronic access monitoring of BES Cyber Systems. ~~This does not apply to control for BES Cyber System.~~
Electronic Security Perimeter (ESP)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.	RETIRED
External Routable Connectivity (ERC)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security	The ability to access an isolated BES Cyber System from a ~~Cyber~~ cyber ~~Asset~~ asset ~~that is outside of its associated Electronic Security Perimeter~~ via a bi-directional routable protocol connection.

Commented [JM23]: Based on conversations with the BCS definition. Serial exclusion can be removed here too.

Commented [JM24]: Consider cross-referencing CIP-005 R1 in place of access permissions.

Commented [JM25]: Ad hoc group CIP-007 and CIP-010 and CIP-005 groups consider this as you are going through your standards and if CMS comes up. If it does, does the current proposed definition work with your standard and how it uses CMS?

Commented [JM26]: CIP-005 to consider adding a requirement for separating CMS from the cyber systems and protection requirements. (everything that an ECAMS is should be considered when drafting a requirement.)

What does cyber system mean? Everything? Do we want to add BCS or should it be considered as an applicability statement in the applicability section.

Commented [JM27]: CIP-005 Ad Hoc group recommends deleted CMS term all together. See CIP-005 R3.

Commented [JM28]: Is this sentence needed? Consider if should be added to IS def.

Commented [JM29]: Consider including PSP reference. Related to PACS

Commented [JM30]: CIP-005 Ad hoc group modified definition.

	Perimeter via a bi-directional routable protocol connection.	
Intermediate System (IS)	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.	A ~~Cyber Asset or collection of Cyber Assets~~system between BES Cyber Systems and non-applicable systems that performs access control to restrict Interactive Remote Access to only authorized users. ~~The Intermediate System must not be located inside the Electronic Security Perimeter.~~
Interactive Remote Access (IRA)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.	User-initiated access to a BES Cyber System from outside a medium or high impact BES Cyber System. Interactive Remote Access does not include system-to-system process communications or access initiated from an Intermediate System. User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from an ~~Cyber A~~asset that is not an Intermediate System and is not located within any of the Responsible Entity's BES Cyber Systems. ~~Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants.~~ Interactive remote access does not include system-to-system process communications.
Cyber Security Incident	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.	On hold until CIP-008 is completed.
Management Interface	NEW TERM	A logical interface that allows configuration and modification of BES Cyber Systems.
Secure Configuration	NEW TERM	A Secure Configuration includes the following items (per system capability):

Commented [JM31]: Out of context here. Needs to be replaced by…

May be able to delete between BCS and X.

Commented [JM32]: Address TCA issue. Do not believe it should be captured in this def. but with the way it is written, TCA is a part of this def.

Commented [JM33]: CIP-005 Ad hoc group modified definition.

Commented [JM34]: Needs more detail added once control is developed within CIP-005. Will compliment CMS.

Commented [A35]: Security planning prior to this?

Planning (Policy & Procedures)
Identifying and Implementing
Controlling
Monitoring

		1.1.1. Operating system, or firmware, including version; 1.1.2. Installed software applications including version; 1.1.3. Executable script and custom software storage locations and location contents; 1.1.4. Installed security updates; 1.1.5. Identified isolation method from CIP-005 R1; 1.1.6. Identified control(s) used to mitigate unauthorized connectivity from CIP-007 R1; 1.1.7. Identified method(s) to protect against malicious code from CIP-007 R3; 1.1.8. Identified minimum Logging and alerting configurations from CIP-007 R4; 1.1.9. Identified minimum authentication and password complexity and expiry configurations from CIP-007 R5; and 1.1.10. Any additional entity Identified controls employed to ensure BES reliability, if necessary
Physical Security Perimeter	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.	The physical border surrounding locations in which ~~BES Cyber Assets~~, BES Cyber Systems~~,~~ or EACS ~~Electronic Access Control or Monitoring Systems~~ reside, and for which access is controlled.
Removable Media	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber ~~Asset~~Systems, ~~a network within an ESP,~~

Commented [JM36]: Need more discussion around definition v. requirement within a definition. SDT agrees with the concept. Just need to work through layout a bit more.

Commented [SK37]: Discussions on GPO and templates to be included in IG.

Commented [JM38]: SDT wants this to be a requirement instead of a definition. Ad hoc group to put this back into CIP-010.

Commented [JM39]: monitoring removed to add flexibility for EAMS

Commented [JM40]: Needs to be updated to mean all the applicable systems within the CA definition. Updating to BCS does not make sense here.

Commented [JM41]: Consider rewording to: Bc of systems concept

	directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.	or a Protected Cyber ~~Asset~~System. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Commented [JM42]: Can be removed pending retirement of PCS.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Issues Steering Committee

Report on Resilience

November 8, 2018

RELIABILITY | ACCOUNTABILITY

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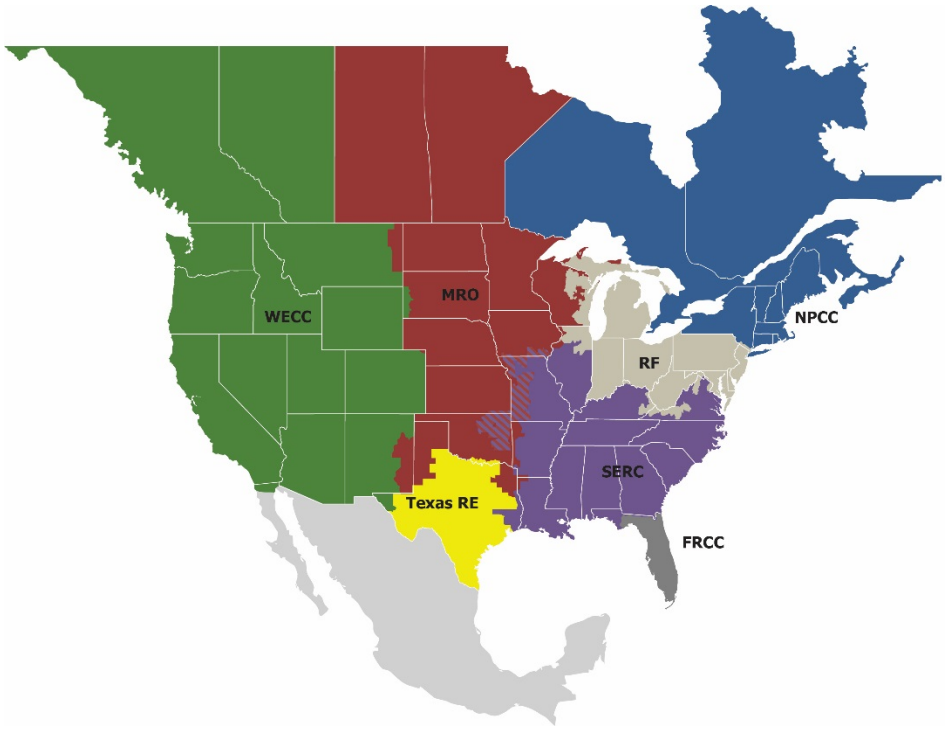
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven 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 seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

In August of 2017, the Department of Energy (DOE) issued a Staff Report to the Secretary on Electricity Markets and Reliability (DOE Grid Report) regarding reliability and resilience in light of the changing energy environment.[1] One recommendation in the DOE Grid Report stated that NERC should consider adding resilience to its mission and broadening its scope to address resilience. In response to the DOE report and NERC assessments, the NERC Board of Trustees (NERC Board) directed the Reliability Issues Steering Committee (RISC or Committee) to develop a framework for resilience and examine resilience in today's environment. At the November 2017 NERC Board Meeting, Board Chair, Mr. Roy Thilly commented that, *"resilience is already built into what NERC does, and NERC is not looking to expand scope but rather to examine resilience more closely. The NERC Board requested that the RISC report back with a framework on how to think about resiliency in the context of reliability."*

In accordance with the NERC Board's directive, the RISC has worked with NERC stakeholders to reexamine the meaning of resilience in today's changing environment and how resilience impacts NERC activities. Meanwhile, the DOE and Federal Energy Regulatory Commission (FERC) have continued evaluating the relationship of resilience and reliability. This report summarizes the results of the RISC's examination of resilience, including the RISC Resilience Framework.

Since its inception, NERC has focused on the ability to withstand and manage event impacts, and respond to emerging issues and risks to ensure the Reliable Operation of the BPS.[2] Resilience is a performance characteristic of the Reliable Operation of the BPS and a critical part of ERO Enterprise activities. Per its statutory mission, NERC has an essential leadership role in identifying and mitigating evolving and emerging risks to reliability. Further, as a learning industry, NERC supports sharing of lessons learned and monitors system performance to identify evolving and emerging risks. Through its subject authority over BES reliability and its reliability programs, NERC can identify and share ways industry can increase resiliency of the BES to resist anticipated threats.

In particular, NERC must develop and enforce Reliability Standards for Reliable Operation on the BES of the BPS and conduct periodic assessments of the reliability and adequacy of the BPS in North America. For over 50 years, "reliability" for the BPS has been defined to consist of two fundamental and aspirational concepts:

- ***Adequacy*** *is the ability of the electric system to supply the aggregate electrical demand and energy requirements at the end-use customers* ***at all times****, taking into account scheduled and reasonably expected unscheduled outages of system elements.*
- ***Operating reliability*** *(formerly titled Security) is the ability of the electric system to* ***withstand sudden disturbances*** *such as electric short circuits or unanticipated loss of system components.*

A resilient BPS should provide an Adequate Level of Reliability (ALR).[3] Resilience is a critical aspect of reliability of the BPS and central to NERC's mission. Based on its analysis of resilience, the RISC has determined that:

1. Resilience has consistently been, and should continue to be, a central component of NERC's mission to "assure the effective and efficient reduction of risks to the reliability and security of the grid;"

[1] https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

[2] Reliable Operation of the BPS is defined in section 215 of the Federal Power Act (FPA) 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." 16 U.S.C. §824o(a)(4). As discussed in section 215 of the FPA, the BPS and NERC's jurisdiction, "does not include facilities used in the local distribution of electric energy." 16 U.S.C. §824o(a)(1).

[3] *See,* Chapter 2 for discussion of NERC's definition of the ALR, as filed with FERC. The ALR is *available at* https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_ALR_Definition_clean.pdf.

2. That the National Infrastructure Advisory Council (NIAC) Framework for establishing Critical Infrastructure Goals (NIAC Framework) serves as an appropriate framework for resilience as refined by the RISC and further informed by NERC's FERC-filed definition of what constitutes the ALR of the Bulk Electric System (BES);
3. That NERC currently engages in a broad array of activities in support of resilience, as demonstrated by the RISC Resilience Framework's mapping of NERC activities to aspects of resilience, and as called for in NERC's Reliability Standards;
4. That NERC should continue pursuing activities to further support a resilient and reliable BPS, as illustrated by standing committee suggestions to the RISC and NERC's Workshop on Gas Infrastructure Risk ;
5. NERC should expand reliability assessment activities to support, in conjunction with industry stakeholders, the development of a model or metrics to measure the resilience and energy security of the BPS; and
6. NERC standing committees should work to develop additional guidance around achievement of both resilience and energy security, focusing on flexible design approaches, and timely recovery processes for differing threats.
7. NERC continue to work with the North American Transmission Forum (NATF), the Electric Power Research Institute and other industry partners to facilitate sharing of industry practices and experiences related to addressing resilience issues as well as performing needed research and development activities.

Introduction

The electric sector is in the midst of unprecedented evolution in both the pace and magnitude of change. This evolution is driven by a number of factors which include economics, new technology, public policy priorities, and customer expectations. The changing resource mix, for example, is altering the operational characteristics of the BPS. NERC's reliability assessments have identified and analyzed the manner in which the generation resource mix has been evolving from a fleet that primarily relies on coal, hydro and nuclear generation to one with increasing levels of non-synchronous and natural gas-fired resources. Non-synchronous generation fueled by the sun and wind introduces greater diversity to the resource mix and is independent from traditional fuel transportation systems, although these resources may be challenged by fuel uncertainty. With the discovery of new drilling technologies, natural gas-fired generation has become a predominant conventional resource addition as older plants retire, although these resources may also introduce uncertainty as they can be susceptible to fuel interruptions due to the nature of fuel procurement and gas transport capacity in some areas in North America. Similarly, inverter based resources introduce new opportunities and potential new vulnerabilities in the form of resource tripping or blocking during some disturbances. Battery storage is also increasingly being considered as alternative to meet system and local needs. On the cyber and physical security front, the landscape grows ever more complex as the electric sector confronts an expanding array of malicious threats and actors. Working with stakeholders, NERC and the ERO Enterprise as a whole must continue to assure the effective and efficient reduction of risks to BPS reliability and security as the industry undergoes rapid transformation. This focus is necessary to ensure that the electric sector continues to evolve with sufficient levels of resilience which is critical for Reliable Operation of the BPS.

The RISC is an advisory committee reporting to the NERC Board that provides front-end, high-level leadership for issues of strategic importance to BPS reliability. The RISC advises the NERC Board, NERC Standing Committees, NERC staff, regulators, Regional Entities, and industry stakeholders to establish a common understanding of the scope, priority, and goals for the development of solutions to address these issues. Every two years, RISC produces the ERO Reliability Risk Priorities Report.[4] In performing these activities, the RISC provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and industry effectively focus their resources on the critical issues needed to best improve the reliability of the BPS.

In August of 2017, the DOE issued the DOE Grid Report regarding reliability and resilience in light of the changing energy environment. One recommendation stated that NERC should consider adding resilience to its mission statement and work with its members to broaden its ways of addressing resilience.[5] On November 9, 2017, in response to the DOE report and NERC assessments, the NERC Board directed the RISC to develop a framework examining resilience, its definition, and NERC activities contributing to resilience.

As noted above, pursuant to the Board's directive, the RISC developed a Resilience Framework based on the NIAC Framework and further informed by NERC's, FERC-filed, definition of the ALR. Relying on these prior activities, the RISC prepared a Resilience Framework mapping ERO Enterprise activities to four outcome-based abilities of resilience: (1) robustness; (2) resourcefulness; (3) rapid recovery; and (4) adaptability. The RISC then requested NERC Standing Committee feedback, to assist with its subsequent evaluation of whether NERC should take additional steps to address key elements of BPS resilience. At the same time, the RISC monitored NERC's Natural Gas Workshop held

[4] https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf.
[5] https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

on July 10, 2018 and focused on evaluating solutions to potential resilience issues associated with fuel adequacy and assurance presented by increasing dependence on natural gas-fired generation.

While NERC's reexamination of resilience was underway, on October 10, 2017, the DOE submitted a proposed rule to FERC on grid reliability and resilience pricing. NERC and other stakeholders provided comments in that proceeding. On January 8, 2018, FERC issued an order terminating the DOE's proposed rule and initiating a new proceeding to define and examine resilience. FERC's proposed definition of resilience was based on the NIAC Framework and FERC asked whether resilience was addressed by existing operating procedures, Regional Transmission Operator/Independent System Operator (RTO/ISO) planning processes, and NERC Reliability Standards. RTO/ISO comments were filed on March 9, 2018 and reply comments were filed by NERC and other stakeholders on May 9, 2018. Consistent with the RISC's findings, NERC's comments focused on resilience as an element of Reliable Operation of the BPS. NERC explained that reliability encompasses aspects of resilience of the BPS consistent with NERC's statutory mission, the definition of the ALR, and NERC activities. NERC's comments also presented the RISC Resilience Framework.[6] These issues were addressed once more in NERC's testimony by James Robb, President and Chief Executive Officer and Mark Lauby, Senior Vice President and Chief Reliability Officer at the FERC Reliability Technical Conference of 2018.[7] Mr. Lauby's testimony at the resilience panel stated, "[a]s the Electric Reliability Organization (ERO), a highly reliable and secure grid is at the heart of our vision and the very foundation of the ERO Enterprise. NERC, and the Regional Entities (REs) which make up the ERO Enterprise, work with industry every day to identify risks to reliability, prioritize actions, and implement mitigation strategies."[8]

This report presents the RISC's findings in response to the NERC Board's directed evaluation of resilience and summarizes relevant regulatory proceedings.

[6] *See, Comments of NERC in Response to Grid Reliability and Resilience Pricing NOPR*; *and* NERC Reply Comments on FERC Grid Resilience Proceeding (for NERC comments in FERC Docket Nos. RM18-1-000 and AD-18-7-000 respectively).

[7] *See,* https://www.ferc.gov/CalendarFiles/20180731083512-Robb,%20NERC.pdf (providing James Robb's testimony); *and* https://www.ferc.gov/CalendarFiles/20180731083852-Lauby,%20NERC.pdf (providing Mark Lauby's testimony).

[8] https://www.ferc.gov/CalendarFiles/20180731083852-Lauby,%20NERC.pdf, at p. 1.

Chapter 1: The RISC's Commitment to Evaluate Resilience

Overview of the NERC Board's Directive to Evaluate Resilience

The DOE Grid Report was issued after the Secretary of the DOE requested a grid study to examine the evolution of wholesale electricity markets, compensation for resilience in wholesale energy and capacity markets, and baseload power plant retirements. The DOE Grid Report asserted that a combination of market and policy forces, including low natural gas prices, low electricity growth, environmental regulations, and increased variable renewable energy penetration, have accelerated the closure of a significant number of traditional baseload power plants. In addition, the DOE Grid Report noted that: (1) bulk power reliability is adequate today, but long-term concerns about baseload retirements require further study; (2) markets recognize and compensate reliability, but more work is needed to understand resilience across a variety of scenarios; and (3) growing natural gas interdependence still needs to be addressed.

One recommendation of the DOE Grid Report stated that NERC should consider including resilience as an explicit part of its mission. The DOE Grid Report provided: "NERC should consider adding resilience components to its mission statement and develop a program to work with its member utilities to broaden their use of emerging ways to better incorporate resilience."

After reviewing the DOE Grid Report and its recommendations, the Board directed the RISC to reexamine resilience and its definition, propose a resilience framework, review NERC's ongoing activities and their contributions to resilience, and make recommendations for any additional actions.

Chapter 2: RISC Evaluation of Resilience and Development of the Resilience Framework

In response to the NERC Board's directive, the RISC initiated activities to examine resilience in today's environment, leveraging prior efforts to address resilience. Through its analysis of the issues, the RISC determined that resilience is an existing and central component of NERC's mission, created a Model for Reliable Operation of the BPS, and developed the NERC Resilience Framework.

The RISC Resilience Framework is presented below at **Table 1.1** as the culmination of these efforts and a tool supporting NERC activities in favor of resilience. In particular, the RISC Resilience Framework is intended to accomplish the following:

1. Develop a common understanding and definition of the key elements of BPS resilience;
2. Understand how these key elements of BPS resilience fit into the existing ERO framework; and
3. Evaluate whether there is a need to undertake additional steps, within the ERO framework, to address these key elements of BPS resilience beyond what is already in place and underway in connection with ongoing ERO Enterprise operations, including work being undertaken by each of the NERC standing committees.

Leveraging Prior Efforts Addressing Resilience

The RISC determined that it should begin developing a NERC Resilience Framework by building on prior efforts addressing resilience, including the NIAC Framework. As a result, the RISC Resilience Framework relies on the NIAC Framework as a credible source for understanding resilience, which breaks down resilience into four outcome-focused abilities: (1) robustness; (2) resourcefulness; (3) rapid recovery; and (4) adaptability.

The RISC Resilience Framework is based on the NIAC Framework, with additions in red proposed by the RISC based on standing committee feedback in March of 2018. Four outcome-based abilities of resilience are included as follows:

- **Robustness** – the ability to absorb shocks and continue operating
- **Resourcefulness** – the ability to detect and manage a crisis as it unfolds
- **Rapid recovery** – the ability to get services back as quickly as possible in a coordinated and controlled manner and taking into consideration the extent of the damage
- **Adaptability** – the ability to incorporate lessons learned from past events to improve resilience

In particular, the RISC modified the NIAC Framework to include the ability to detect a crises (such as cyber incidences or equipment failure modes) within the scope of resourcefulness and include the ability to ensure rapid recovery is performed in a coordinated and controlled manner as provided in the ALR.

Resilience as an Existing and Central Component of NERC's Mission

While developing the Resilience Framework, the RISC determined that resilience is an existing and central component of NERC's mission to support Reliable Operations of the BPS. The RISC's May 2018 presentation to the Member Representatives Committee (MRC) detailed the RISC's evaluation of resilience as a key aspect of NERC's mission.

As provided in section 215 of the FPA, NERC develops Reliability Standards based on what is necessary to achieve an ALR for Reliable Operations. When FERC certified NERC as the ERO, it ordered that a definition of the ALR be submitted to FERC. NERC accordingly developed, filed, and later updated a definition of the ALR[9] along with a technical report[10] to guide Reliability Standards development, Reliability Assessments, and standing committee work. In particular, the ALR is defined as the state that design, planning, and operation the BES will achieve when five performance objectives are met.[11]

Each objective addresses Reliable Operation of the BES over four time frames:

1) **Steady state:** the period before a disturbance and after restoration has achieved normal operating conditions
2) **Transient:** the transitional period after a disturbance and during high-speed automatic actions in response
3) **Operations response:** the period after the disturbance where some automatic actions occur and operators act to respond
4) **Recovery and system restoration:** the time period after a widespread outage through initial restoration to a sustainable operating state and recovery to a new steady state

These periods of time generally correspond to the four outcome-based abilities of the NIAC Framework and FERC's proposed definition of resilience. (*See* **Chapter 3** below for discussion of that proceeding). NERC must develop and enforce Reliability Standards on the BES for Reliable Operation of the BPS as well as assess reliability and adequacy of the BPS in North America.[12]

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[9] https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_ALR_Definition_clean.pdf.

[10] https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf.

[11] The ALR Performance Objectives are as follows:

1) The BES does not experience instability, uncontrolled separation, Cascading, or voltage collapse under normal operating conditions and when subject to predefined Disturbances.
2) BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined Disturbances.
3) BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined Disturbances.
4) Adverse Reliability Impacts on the BES following low probability Disturbances (e.g., multiple contingences, unplanned and uncontrolled equipment outages, cyber security events, and malicious acts) are managed.
5) Restoration of the BES after major system Disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

The ALR also lists two assessment objectives for purposes of assessing risks to reliability:

1) BES transmission capability is assessed to determine availability to meet anticipated BES demands during normal operating conditions and when subject to predefined Disturbances.
2) Resource capability is assessed to determine availability to the Bulk Electric System to meet anticipated BES demands during normal operating conditions and when subject to predefined Disturbances.

[12] Section 215 of the FPA specifically does not authorize the ERO to develop standards related to adequacy and safety.

The ALR provides granularity of NERC's definition of BPS reliability which consists of two fundamental concepts that encompass aspects of resilience:

- ***Adequacy*** *is the ability of the electric system to supply the aggregate electrical demand and energy requirements at the end-use customers* ***at all times****, taking into account scheduled and reasonably expected unscheduled outages of system elements.*
- ***Operating reliability*** *is the ability of the electric system to* ***withstand sudden disturbances*** *such as electric short circuits or unanticipated loss of system components.*[13]

As stated in the companion technical report to the definition of ALR:

> *Simply stated, the ALRTF's goal is to develop a definition of ALR that encompasses NERC's responsibility to ensure reliable planning and operation of the BES, along with the obligation to assess the capability of the BES. The definition identifies and defines Reliability Performance Objectives that drive what system planners and operators do on a day-to-day basis to ensure that the BES is reliable and defines Reliability Assessment Objectives that identify risks to system reliability that alert system planners and operators so appropriate actions can be taken…*
>
> *ALR is clearly not a single value or outcome or state; rather, ALR is an outcome of a multi-dimensional effort to identify Reliability Performance and Assessment Objectives and then achieve outcomes that will support reliable operations. This multi-dimensional effort is reflected in NERC's current and evolving body of reliability standards, which work together to establish a portfolio of performance outcomes, risk reduction, and capability-based reliability standards that are designed to achieve an in-depth defense against an inadequate level of reliability. Other NERC programs, such as industry alerts; reliability assessments; event analysis; education; the compliance with and enforcement of reliability standards, are designed to work in concert with reliability standards to support reliable operation. Each of these activities should be driven by the goal of consistently achieving an adequate level of reliability.* [14]

[13] Adequacy assumes a certain level of forecast demand distribution does not cover all events that may occur. System are design cover a level of probabilistic service interruption (i.e. 1 event in 10 years) considering the distribution of louds and outages.

[14] *Technical Report Supporting Definition of Adequate Level of Reliability*, at pp. 1-2.

The RISC's Model for Reliable Operation of the BPS

Leveraging the NIAC Framework and the NERC ALR, the RISC created a model depicted in Figure 1 below that illustrates and enables measurement of system performance, or resilience, and provides an understanding of the elements needed to support the Reliable Operation of the BPS. Measuring the profile represented in this model provides relative characteristics of system performance, identifies areas where improvements may be desired, post events, and measures the success from system improvements. Some of the key areas that lend themselves for measurement are robustness, amplitude, degradation, recovery, and recovery state.

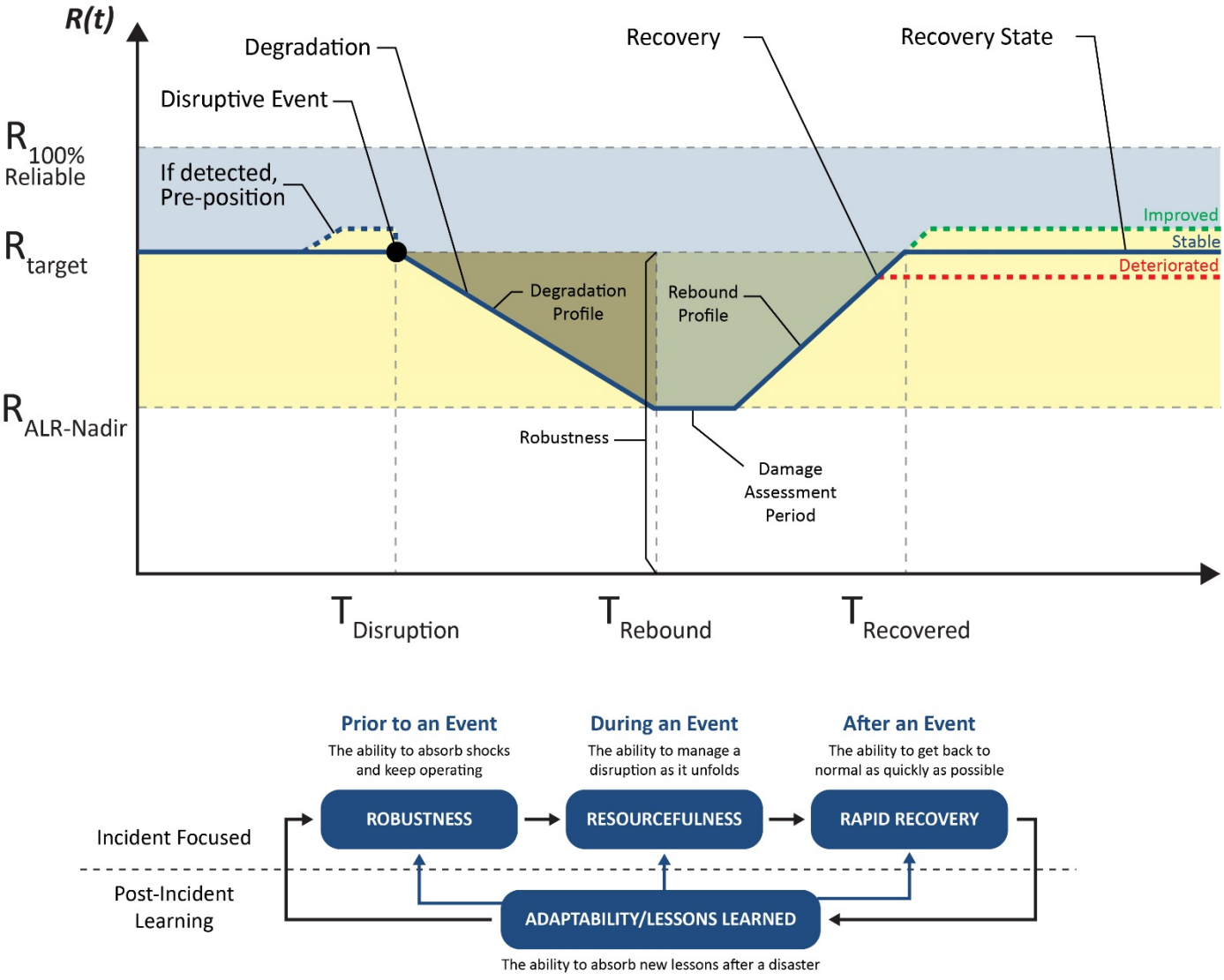

Fig. 1

The RISC Resilience Framework as a Tool to Support Resilience

Relying on the NIAC Framework, NERC ALR, and the RISC Model described above, the RISC prepared a NERC Resilience Framework to map current ERO Enterprise activities to the four outcome-based abilities of the NIAC Framework. By bringing together the concepts in the refined NIAC Framework and NERC's definition of the ALR, the RISC has arrived at an overall NERC-specific Resilience Framework. The RISC Resilience Framework reflects the realization that Reliable Operation varies and is a function of time.

Recognizing that the BPS cannot withstand all potential events, an adequate level of reliability must be provided so that the system can be reliably operated even with degradation in reliability due to an event. Further the system must have the ability to rebound or recover when repairs are made, or system conditions are alleviated. The resulting RISC Resilience Framework provides guidance on how resilience fits into NERC's activities and how additional activities might further support resilience of the grid. The RISC Resilience Framework underscores NERC's longstanding focus on aspects of resilience and emphasis on reexamining the issue in the face of the changing resource mix.

The **Table 1.1** below provides the RISC Resilience Framework and the associated NERC activities that support the NIAC outcome-based abilities.[15]

[15] Other activities are ongoing with industry and governmental entities, such as NATF and the DOE.

Table 1.1: RISC Resilience Framework		
NIAC Resilience Constructs[16]	**Key Programs and Activities**	**Specific Efforts\Tools**
Robustness—The ability to continue operations in the face of disaster. In some cases, it translates into designing structures or systems to be strong enough to take a foreseeable punch. In others, robustness requires devising substitute or redundant systems that can be brought to bear should something important break or stop working. Robustness also entails investing in and maintaining elements of critical infrastructure so that they can withstand low probability but high consequence events.	• Reliability and Emerging Risk Assessments • Risk, Event and Performance Monitoring • Technical Committee work, including special projects • Mandatory Reliability Standards • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training • E-ISAC information sharing programs	• Alerts • State of Reliability Report ▪ GADS ▪ TADS ▪ DADS ▪ Protection system misoperations ▪ TEAMS ▪ FR Performance • Long-Term Reliability Assessment • Key Reliability Standards: ▪ TPL (Extreme) ▪ EOP ▪ Blackstart Restoration ▪ Personnel Credentials • GridEx • Security conferences and information sharing (e.g. GridSecCon) • Supply Chain Security • Security Practices
Resourcefulness—The ability to skillfully detect and manage a disaster as it unfolds. It includes identifying options, prioritizing what should be done both to control damage and to begin mitigating it, and communicating decisions to the people who will implement them. Resourcefulness depends primarily on people, not technology.	• Situational Awareness and Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Mandatory Reliability Standards/Functional Model • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• BPSA information sharing tools and processes • E-ISAC information sharing tools and processes • Formation of a Crisis Action Team to support industry and governmental coordination • GridEx • Standards requirements ▪ Reliability Coordinators ▪ Transmission Operators ▪ Communications
Rapid recovery—The capacity to get things back to normal as quickly as possible after a disaster in a coordinated and controlled manner and taking into consideration the extent of the damage. Carefully drafted contingency plans, competent emergency operations, and the means to get the right people and resources to the right places are crucial.	• Situational Awareness, Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• Support for Electric Sector Coordinating Council activities • BES simulation • System restoration coordination

NIAC Resilience Constructs	Key Programs and Activities	Specific Efforts\Tools
Adaptability—The means to absorb new lessons that can be drawn from a catastrophe. It involves revising plans, modifying procedures, and introducing new tools and technologies needed to improve robustness, resourcefulness, and recovery capabilities before the next crisis.	• Reliability and Emerging Risk Assessments • Event Analysis • Event Forensics • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training • Periodic Review	• Technical Committee Recommendations • Reliability Guidelines • Lessons Learned • Event Analysis, Investigations • Audit Recommendations • Reliability Assessments • State of Reliability Report • Annual BES Security Assessment • BES Security Metrics • Training • BES simulation • Emergency operations

[16] Those items in red indicate NERC additions to the NIAC framework that includes the ability to detect (such as cyber incidences or equipment failure modes), or ensure rapid recovery includes that it is performed in a coordinated and controlled manner per the ALR.

Chapter 3: Resilience Proceedings by Governmental Authorities

Overview of the Proceedings and Initial Comments

On October 10, 2017, following the DOE Grid Report, the DOE submitted a proposed rule on grid reliability and resilience pricing to FERC. On January 8, 2018, FERC issued an order terminating the DOE's proposed grid resilience pricing rule and initiating a new proceeding to examine resilience.[17] FERC proposed to define resilience as, "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[18] FERC based its proposed definition on the NIAC framework. In addition, FERC asked whether existing operating procedures, RTO/ISO planning process, and NERC Reliability Standards address resilience and whether they should be modified to better address resilience.[19]

Initial RTO/ISO comments were filed with FERC on March 9, 2018. Reviewing RTO/ISO comments, the RISC noted:

- Most RTOs/ISOs generally appeared to have perspectives on reliance that were consistent with FERC's proposed definition of resilience and the (then draft) RISC Resilience Framework.
- Most RTOs/ISOs commented that their planning processes take into account reliability and resilience.
- RTO/ISO comments did not indicate a gap in relation to the RISC's discussions.
- Several RTOs/ISOs highlighted regional concerns and the value of interregional coordination, NERC Reliability Standards, and resource diversity.

NERC's Reply Comments in FERC's Resilience Proceeding

On May 9, 2018, NERC and other stakeholders filed reply comments in the proceeding. Consistent with the RISC's evaluation of resilience, NERC's comments focused on resilience as an element of Reliable Operation of the BPS and as related to the ALR of the BES. NERC explained that reliability encompasses aspects of resilience of the BPS, consistent with section 215 of the FPA and NERC's obligation to develop Reliability Standards supporting Reliable Operation of the BPS. NERC described how elements of resilience are incorporated into NERC's definition of the ALR.

NERC's comments also summarized activities under Reliability Standards, Reliability Assessments, Event Analysis, Situational Awareness, and the Electric-Information Sharing Analysis Center (E-ISAC) in support of resilience of the BPS. For example, NERC's comments highlighted that, as recognized by RTOs/ISOs in the proceeding, NERC Reliability Standards incorporate resilience by supporting robustness, resourcefulness, rapid recovery, and adaptability. These Reliability Standards relate to the BPS's capability to withstand disturbances in anticipation of potential events, manage the system after an event, and/or prepare to restore or rebound after an event. For example, NERC has developed the following:

- Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*): regarding planning performance requirements in anticipation of potential events;
- Reliability Standard EOP-004-3 (*Event Reporting*): requiring that entities report disturbances and events threatening reliability;

[17] *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Order").
[18] Order, P 23.
[19] Order, P 27.

- Reliability Standard EOP-005-2 (*System Restoration from Blackstart Resources*): requiring preparation for system restoration from Blackstart resources;
- Reliability Standard EOP-006-2 (*System Restoration Coordination*): requiring that plans and personnel be prepared to support system restoration after an event;
- Reliability Standard EOP-011-1(*Emergency Operations*): requiring operating plans to mitigate emergencies;
- Reliability Standard CIP-006-6 (*Cyber Security – Physical Security of BES Cyber Systems)*: requiring a physical security plan in support of protecting BES Cyber Systems;
- Reliability Standard CIP-008-5 (*Cyber Security - Incident Reporting and Response Planning*): requiring plans to address reportable cyber security incidents;
- Reliability Standard CIP-014-2 (*Physical Security*): pertaining to physical security; and
- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): on planning to withstand a predefined level of geomagnetic disturbances.[20]

Other Reliability Standards codify obligations to implement lessons learned and thereby adapt after an event. See, for example:

- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): requiring corrective action plans if a geomagnetic disturbance vulnerability assessment concludes that the system does not meet certain performance requirements;
- Reliability Standard PRC-004-5 (*Protection System Misoperation Identification and Correction*): requiring a corrective action plan after Protection System Misoperations or declaration explaining why corrective action plans are beyond the entity's control or would not improve BES reliability;
- Reliability Standard PRC-006-3 (*Automatic Underfrequency Load Shedding*): requiring a corrective action plan where the automatic underfrequency load shedding ("UFLS") design assessment determines that the UFLS program does not meet certain performance characteristics; and
- Reliability Standard PRC-016-1 (*Remedial Action Scheme Misoperations*): regarding corrective actions to avoid future remedial action scheme misoperations.[21]

In addition to Reliability Standards, NERC's comments described Reliability Assessments and Event Analysis on issues impacting resilience, such as NERC's 2017 *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System* and *Alert 1200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report.* NERC also highlighted activities by the E-ISAC such as GridEx and the Cybersecurity Risk Information Sharing Program. Finally, NERC described work being completed by the RISC to reexamine resilience and potential additional NERC activities in support of resilience.[22]

Third Party Comments on FERC's Resilience Proceeding

A wide variety of third party comments were filed in the latest FERC proceeding, reflecting the diversity of issues affecting resilience. The RISC reviewed these comments as part of evaluating resilience pursuant to the NERC Board's directive. Reviewing third party comments, the RISC observed that:

[20] *See*, NERC Complete Set of Reliability Standards, *available at*, https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf (last updated Feb. 15, 2018) (providing the full set of NERC Reliability Standards).
[21] *Id.*
[22] *Supra* n. 4.

- Comments widely recognized NERC activities in support of resilience.
- Several commenters underscored FERC's limited jurisdiction over the electric and natural gas distribution systems.
- Many commenters highlighted regional differences impacting resilience.
- Several comments highlighted the role of transmission infrastructure in resilience.
- Comments presented varying perspectives on the extent to which reliance on natural gas-fired generation is impacting or could impact resilience of the BPS.

Chapter 4: Standing Committee Recommendations

As mentioned above, the RISC requested NERC standing committee feedback regarding activities addressing resilience. In particular, the RISC requested input from the Compliance and Certification Committee (CCC), Critical Infrastructure Protection Committee (CIPC), Operating Committee (OC), Personnel Certification and Governance Committee, Planning Committee (PC), and Standards Committee (SC) on the RISC Resilience Framework.

The RISC requested that these committees comment on:

1. The committee's views on how BPS resilience is currently being addressed within the scope of the committee's responsibilities; and
2. Any additional activities the committee believes should be undertaken.

All committees supported the Resilience Framework. Standing committee comments underscored that resilience is an existing concept, reflected within the definition of the ALR as well as definitions of Reliability, Adequacy, and Security. The CCC, CIPC, OC, and SC also suggested additional activities that might support resilience. Some additional activities included, for example, revisions to standards process templates and training materials, enhanced communication of NERC's ongoing resilience and risk mitigation efforts, additional compliance monitoring focus on standards supporting resilience, and additional focus on areas that might impact resilience. The RISC will review these suggestions as input to the 2019 RISC Report for potential 2020 implementation.

NERC should continue to consider holding activities such those suggested by standing committees and NERC's recent Natural Gas Workshop to ensure that NERC remains at the vanguard of issues affecting reliability, including resilience. Further, NERC should pursue NPCC's recommendations to the Board in August 2018 to 1) expand reliability assessment activities to support, in conjunction with industry stakeholders, the development of metrics to measure the resilience and energy security of the BPS; and 2) NERC Technical Committees should work to develop guidance around achievement of both resilience and energy security, focusing on flexible design approaches, and timely recovery processes for differing threats.

In **Table 2.1** summarizes standing committee suggestions for additional activities to support resilience. These suggestions are presented for consideration to the RISC and for inclusion in standing committee 2020 work plans.

Table 2.1: Standing Committee Suggested Additional Activities	
Standing Committee	**Suggested Additional Activities in Support of Resilience for Consideration**
Compliance and Certification Committee (CCC)	• If there is a gap analysis to be performed related to resilience, it ought to be focused on any missing elements in the definition of Adequate Level of Reliability. • NERC should publish web pages that communicate NERC's ongoing reliance and risk-mitigation efforts related to the RISC report. • NERC should continue to calculate and share key compliance information, specifically CP-1 (risk) and CP-2 (impact) metrics. • The ERO should include resiliency related issues in its Risk Elements as part of driving ERO compliance monitoring efforts.
Critical Infrastructure Protection Committee (CIPC)	• Revise the scope of Resourcefulness within the definition of resilience or NIAC Framework to include detection.
Operating Committee (OC)	Consider recommending existing groups or committees address or enhance reliability in the following areas: • Distributed Energy Resources Bulk Electric System operational impacts, i.e., impacts to Load Forecasting, System Restoration, State Estimation, RTCA results, etc.; • Fuel assurance to promote resiliency; • Quality of emergency preparedness, such as the characteristics of good "communications protocols" or "emergency plans,"; • Interconnection-wide transmission loading relief procedures, such as TLR, to be more timely and precise in order to manage extreme events more effectively; • Incorporate lessons learned from past events to improve resilience, • High Impact, Low Frequency (HILF) events; • Severe Impact Resilience events; • GridEx; • New technologies such as synchrophasors to improve operations and analysis.
Planning Committee (PC)	• Establish a subgroup for the analysis and understanding of the system planning impacts of Distributed Energy Resources; • Fuel assurance/energy security as a means to promote resilience; • Review guidance and other processes to ensure timely and effective protocols exist to aid planners as the technologies advance to produce higher penetrations • Review processes for improving reporting through the Long Term Reliability Assessment and State of Reliability Report • Evaluate systems to ensure appropriate mechanisms are in place to capture pertinent data gathering for generation, transmission, misoperations, and demand resources

Standards Committee (SC)	• Review the Periodic Review Template to consider adding questions about resilience issues for a review team to identify as appropriate to the Standard reviewed. • Review the SAR Template to determine appropriate resilience concerns identified when a new or modified Standard is proposed. • Review the Standards Grading template to add a resilience category to the quality and content review used as an input to prioritize standards projects for the Reliability Standards Development Plan. • Review and revise the Standard Drafting Team training materials to add the NIAC Resilience Constructs and support further explanations to ensure teams sufficiently address resilience concerns.

Chapter 5: Conclusion

NERC's activities, since its inception, have focused on the ability to withstand events, manage event impacts, and respond to emerging issues and risks to ensure the Reliable Operation of the BPS. As the ERO, NERC must identify new and emerging risks to reliability. Resilience is an existing part of NERC's statutory mission to assure the effective and efficient reduction of risks to the reliability and security of the grid. The RISC's examination of resilience demonstrates NERC has consistently considered aspects of resilience as part of what contributes to reliability. While a system able to withstand impacts from all risks is a difficult and costly goal to realize, it is feasible and imperative to establish an adequate level of reliability. A balance is achieved by coupling the ability to withstand impacts to certain design levels with resilience measures that are meant to mitigate risks to reliability and maintain Reliable Operation of the BPS. By leveraging industry expertise, informed by sound technical analysis and support by the ERO Enterprise, NERC's fosters a learning environment to identify and mitigate risks in pursuit of improved reliability. The ERO Enterprise's continued leadership role is essential to maintaining a focus on conventional risk, while anticipating emerging risks during a period of revolutionary change in the electricity sector.

The RISC Resilience Framework, informed by the NIAC Framework and NERC's definition of the ALR, provides an appropriate definition of resilience in today's environment. This definition is consistent with FERC's proposed definition in pending regulatory proceedings. The RISC Resilience Framework demonstrates how various NERC activities support resilience by mapping NERC activities across the ERO Enterprise that are driven towards supporting the ALR and a resilient system. These activities include, Reliability Standards, Reliability Assessments, Event Analysis, GridEx, and E-ISAC work. As described in this report, ERC should continue pursuing activities that support resilience.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-09 SOL

Dean LaForest, Manager – Real Time Studies – ISO New England
NPCC Regional Standards Committee meeting
October 10, 2018

RELIABILITY | ACCOUNTABILITY

NERC Antitrust

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Presentation Approach

- SOL Team info
- Methods for Establishing IROLs Task Force (MEITF) Info
- Very Short Summary of Posting
- Summary of Approach/Standards/Changes
- Standard Page Turn – as needed

Standard Drafting Team

- Chair – Vic Howell (Peak Reliability)
- Vice Chair – Hari Singh (Xcel Energy)
- Members:
  - Dede Subakti (CAISO)
  - Stephen Solis (ERCOT)
  - Dean LaForest (ISONE)
  - Aaron Staley (OUC)
  - Thomas Leslie (GTC)
  - Sam Jager (IESO)
  - David Hislop (PJM)

Vote by October 17, 2018

- 45-day posting for comment and ballot:
  - Revised FAC-011-4
  - Revised FAC-014-3
  - New FAC-015-1
  - Retirement of FAC-010-3
  - Revised definition of SOL
  - Revised standards due to retirement of FAC-010-3

Rationale Documents

- Posted at http://www.nerc.com/pa/Stand/Pages/Project-2015-09-Establish-and-Communicate-System-Operating-Limits.aspx
- "Requirement Rationales" new feature. Combination of:
  - Rationales that used to be in standard
  - Team Technical Justification and commentary
  - White Paper
- Revised NERC SOL White Paper

MEITF

- MEITF
  - Developed IROL Reliability Guideline
  - Developed IROL Framework Document
- IROL-related requirements unchanged in this posting
- Options related to MEITF final products
  - Once approved, file modified/new standards at FERC to address immediate need. Address IROL-related standards as 2nd phase and refile at FERC.
  - Revise IROL-related based on MEITF IROL Framework and then file at FERC.

Overview

- SOL definition: All limits used in operations
- IROL: Unchanged in this posting
- FAC-011-4:
  - Define Thermal, Voltage, and stability limits
  - Define Contingencies used in OPA and RTA
  - Define performance criteria for use in OPA, RTA, and RTM
- FAC-014-3: Communicate
- SOLs are an input to Operational Planning Analyses (OPA), Real-time Monitoring (RTM), and Real-time Assessments (RTA)
  - Assess projected system conditions for potential SOL exceedances (OPA)
  - Develop Operating Plans for SOL exceedances
  - Assess actual system conditions (RTM & RTA)
  - Implement Operating Plans for SOL exceedances

Overview (continued)

- SOL and IROL terms not directly applicable to planning horizon
- Retire FAC-010-3: Redundant with TPL-001-4
- NEW FAC-015-1: Facilitates coordination between planning and operations

Planning SOL and IROLs

- SDT addressed standards impacted by retirement of FAC-010-3
- Planning SOLs and IROLs used in other standards
- Replace “IROL” with pointer to PC/TP Assessments
  - FAC-003-5: Vegetation Management
  - CIP-002-2 Cyber Security (addressed in CIP posting)
  - CIP-014-2: Physical Security
  - PRC-023-5: Transmission Relay Loadability
  - PRC-026-2: Relay Performance during Stable Power Swings
- FAC-013-3: Assessment of Transfer Capability for the Near-term Transmission Planning Horizon – removed reference to SOLs used in planning
- PRC-002-3: Disturbance Monitoring – RC as “Responsible Entity”

System Voltage Limit Definition

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

- Passed first posting
- Will be reposted in final ballot stage

SOL in Operations Concept

- OLD CONCEPT.. Confusing
  - SOLs “provide for” meeting performance requirements? Input or output of studies?
  - Most Limiting?
  - SOLs change with conditions?
  - Pre-Contingency value to hedge for Post-Contingency Condition?
  - All ratings? Some Ratings?
  - Could you have NO SOLs?
- NEW CONCEPT.. ALL LIMITS used for Operations
  - Facility Ratings
  - System Voltage Limits
  - Stability Limits

SOL Definition

Last Posting: *Facility Ratings, System Voltage Limits, and stability limits used in the operation of the Bulk Electric System (BES)*

Current Posting: All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in BES operations for monitoring and assessing pre- and post-Contingency operating states

RC and TOP – How is SOL used in Standards

- Real Time Assessment (RTA)
- Next day Operational Planning Assessment (OPA)
- TOP/IRO Process:
  - Study pre- and post-Contingency states
  - Screen for SOL exceedance
  - Develop/implement Operating Plan for SOL exceedance
- *SOL Exceedance not defined as a NERC Glossary term*
  - *Operational performance criteria in FAC-001-4 requirement R6 and FAC-014-3 requirement R6*
  - *Revised SOL White Paper for descriptions and examples of reliable operational performance*

Where is the capital in “stability limit”

- The Term “stability limit” is purposefully lower case
- NERC Defined “Stability Limit” limited to maximum power flow

“The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers”

FAC-011-4: R1, R2, R3

- RC SOL Methodology (R1)
- Facility Ratings (R2): Which of the owners ratings to use
- System Voltage Limits (R3)
  - Allows exclusion/inclusion of buses
  - Must respect voltage-based Facility Ratings from owner
  - Must be above uvls and UVLS Program settings
  - Must identify lowest allowable System Voltage Limit
  - Requires common use of System Voltage Limits between RC and its TOPs
  - Requires coordination of System Voltage Limits between adjacent TOPs and RCs

FAC-011-4: R4

- Stability Performance criteria and limits (R4)
- RC SOL Methodology:
  - Specifies stability performance criteria (specific criteria required),
  - Requires stability limits to be established to meet that criteria
  - Describes how stability limits are determined, given various considerations
  - Describes level of detail required in study models
  - Describes allowed uses of RAS and other automatic post-Contingency mitigation actions
  - TOP establishes stability limits unless there is multi-TOP impact
  - Required to state that UFLS and UVLS Programs not allowed in establishment of stability limits

FAC-011-4: R5

- Contingencies used in OPA and RTA (R5)
  - Single contingencies (Standard specifies, same as currently effective FAC-011-3)
  - Multiple contingencies if required by RC
  - Method to address events provided by PC/TP
  - Rephrased and added “Area under Study”
    - To allow for a TOP to not have to monitor all of RC

FAC-011-4: R6

- Minimum Performance Criteria (R6)
  - Minimum set by standard
  - Actual / Pre-Contingency: Within Normal (Emergency if adjusting)
  - Post “single” Contingency: Within Emergency
  - Beyond defined “single”: no instability, Cascading, uncontrolled separation
  - RC can set higher bar

FAC-011-4: R6 – Load Shedding

- Planned Load Shedding (R6)

  R6.5: In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

- R6 Rationale (non-binding)
  - *For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:*
    - *Generation commitment and re-dispatch regardless of economic cost*
    - *Curtailment and adjustment of Interchange regardless of economic cost*
    - *Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)*

FAC-011-4: R7, R8, R9

- IROLs (R7) (no change)
  - Describe how SOL becomes IROL
- RC specifies method for TOPs to Communicate SOLs to RC (R8)
- RC shares Methodology (R9)

FAC-014-3: R1 – R5

- RC establish IROLs (R1)
- TOP establish SOLs for its portion of the RC Area (R2)
- TOP provides its SOLs to its RC in accordance with its RC SOL Methodology (R3)
- RC establish multi-TOP stability limits (R4)
- RC share SOLs, IROLs, and related information (R5)
  - Differentiate between “value” and “details” of a stability SOL
  - Added “associated system conditions”
  - Better clarity around use of database/website as evidence (M5)
- TOP and RC use performance criteria in RC’s SOL methodology for OPA, RTA, and RTM to determine SOL exceedances (R6)

Long Term Planning

Long Term Planning - FAC-010

- What is the role of planning entities
  - Analyze transmission systems & develop transmission expansion plans
  - Establish operating limits?
  - Ensure continuity between planning and operations:
    - Bounded planning criteria
    - Identify System risks
    - Share severe study results
- Redundancy Issue
  - Two SOL Methodologies
  - TPL-001
- Retire FAC-010 / Create FAC-015
  - Remove redundancy and add continuity

FAC-015-1

- Criteria equal or more limiting than RC: (R1, R2, R3,)
  - Focus on process to ensure equal or more limiting planning criteria
  - Exceptions allowed:
    - CAP, ambient temperature assumption
    - Technical rationale
- Communicate instability, Cascading, or uncontrolled separation to RC (R4)
  - Identify risks
  - Tool for operators

Long Term Planning Questions?

References to Planning IROL and SOL in Other Reliability Standards

- What is the real need?
  - Risk identification
    - Contingency events
    - Criticality of Facilities
    - Instability, Cascading, or uncontrolled separation
- Replace “IROL” reference
  - CIP-002: Cyber System Categorization
  - CIP-014: Physical Security
  - FAC-003: Vegetation Management
  - PRC-023: Transmission Relay Loadability
  - PRC-026: Relay Performance during Stable Power Swings
  - Long term focus

Long Term Planning IROL and SOL?

- Assign solely to RC
  - PRC-002: Disturbance Monitoring
- Remove “SOL” reference
  - FAC-013: Transfer Capability Assessment

Project Status

- Next SDT meeting in November 2018
- Review industry response and decide on either
  - Final Ballot
  - Additional changes
- More information is available on the project page

  http://www.nerc.com/pa/Stand/Pages/Project-2015-09-Establish-and-Communicate-System-Operating-Limits.aspx

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Questions and Answers

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-001-45**

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.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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.

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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	

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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.

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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
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

February 2018

RELIABILITY | ACCOUNTABILITY

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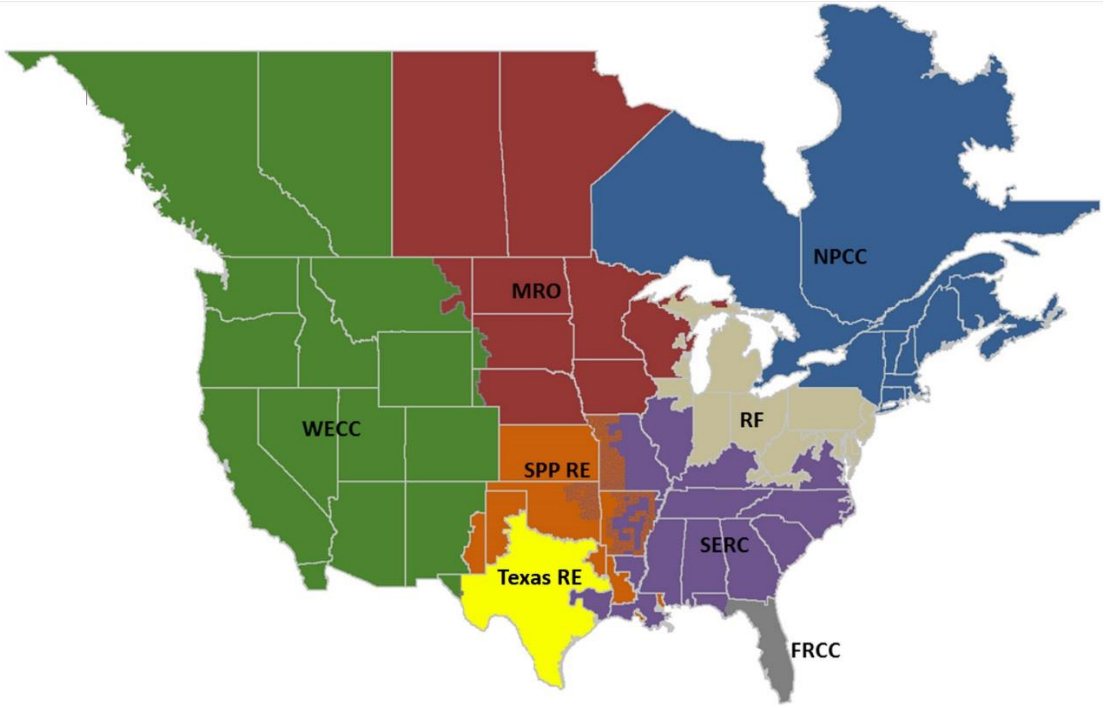
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability 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.

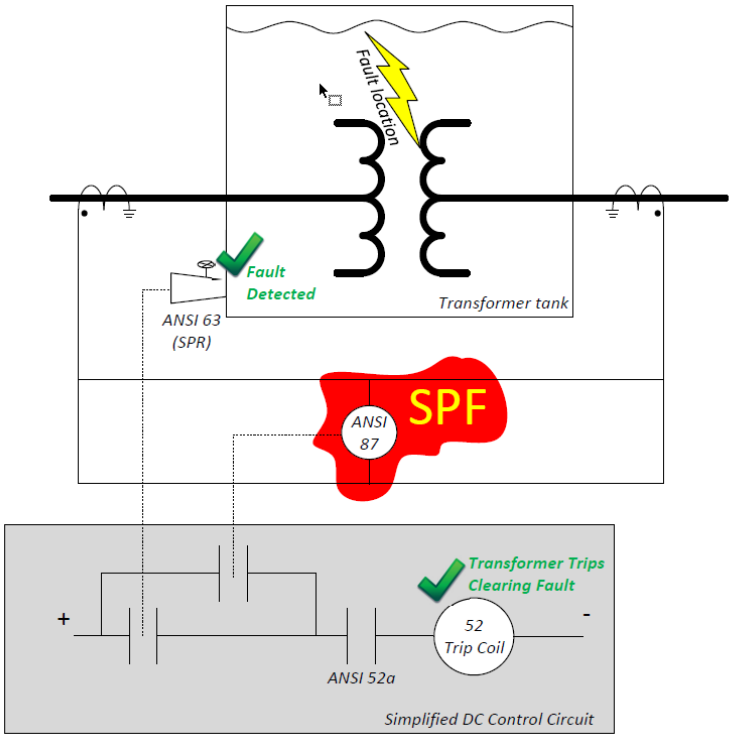


Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

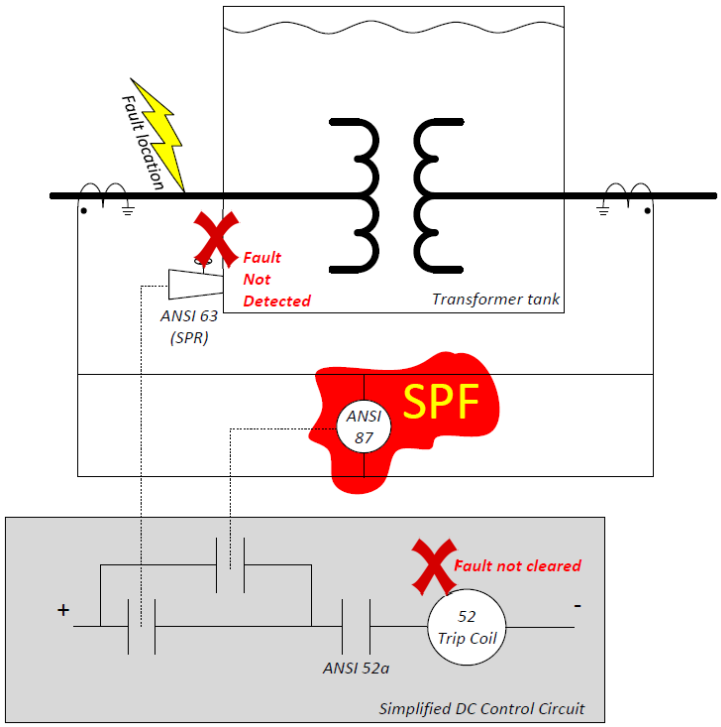


Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

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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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, 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

This implementation 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 procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- 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, 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 CAP actions and establish the associated timetables for completion. This includes any necessary 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 non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

Lastly, the provisions related to 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 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items b, c, and d and P8

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 b, c, and d or P8 until 24 months after the effective date of Reliability Standard TPL-001-5.

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, 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 develop any required CAP under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items b, c, and 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.

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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.

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

15-day informal comment period

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/18 – 03/28/18

Anticipated Actions	Date
~~XX~~45-day formal or informal comment period with ballot	TBD
~~XX~~45-day formal or informal comment period with additional ballot	TBD
~~XX~~10-day final ballot	TBD
Board adoption	TBD

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: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-~~1.1~~2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-~~1.1~~2.

B. Requirements and Measures

R1. 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

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 Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three 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 Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance 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 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.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most ~~30~~15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than ~~15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value

				used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

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	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

~~**Interconnection Frequency Response Obligation (IFRO)**~~

~~The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:~~

~~Prevailing UFLS first step~~

- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.~~

~~Interconnection~~	~~**Eastern**~~	~~**Western**~~	~~**ERCOT**~~	~~**HQ**~~	~~Units~~
~~Starting Frequency (F_{Start})~~	~~**59.974**~~	~~**59.976**~~	~~**59.963**~~	~~**59.972**~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~**59.5***~~	~~**59.5**~~	~~**59.3**~~	~~**58.5**~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~**0.474**~~	~~**0.476**~~	~~**0.663**~~	~~**1.472**~~	~~Hz~~
~~CC_{ADJ}~~	~~**0.007**~~	~~**0.004**~~	~~**0.012**~~	~~**N/A**~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~**0.467**~~	~~**0.472**~~	~~**0.651**~~	~~**1.472**~~	~~Hz~~
~~CB_R~~	~~**1.000**~~	~~**1.625**~~	~~**1.377**~~	~~**1.550**~~	
~~Delta Frequency (DF_{CBR})~~	~~**0.467**~~	~~**0.291**~~	~~**0.473**~~	~~**0.949**~~	~~Hz~~
~~BC'_{ADJ}~~	~~**0.018**~~	~~**N/A**~~	~~**N/A**~~	~~**N/A**~~	~~Hz~~
~~Max. Delta Frequency (MDF)~~	~~**0.449**~~	~~**0.291**~~	~~**0.473**~~	~~**0.949**~~	

Resource Contingency Criteria (RCC)	4,500	2,740	2,750	1,700	MW
Credit for Load Resources (CLR)		300	1,400**		MW
IFRO	-1,002	-840	-286	-179	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$FRO_{BA} = IFRO_ \times \frac{Annual\ Gen_{BA} + Annual\ Load_{BA}}{Annual\ Gen_{Int} + Annual\ Load_{Int}}$$

Where:

- $Annual\ Gen_{BA}$ is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- $Annual\ Load_{BA}$ is total annual Load within the BAA, on FERC Form 714, column c of Part II - Schedule 3.
- $Annual\ Gen_{Int}$ is the sum of all $Annual\ Gen_{BA}$ values reported in that interconnection.
- $Annual\ Load_{Int}$ is the sum of all $Annual\ Load_{BA}$ values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

~~Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.~~

~~Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:~~

- ~~Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or~~
- ~~Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.~~

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

<u>Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.</u>

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the IFRO calculations are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.[1]

Frequency Response Measure (FRM)

The Balancing Authority will calculate 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 events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the

[1] Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is available at https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf

event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

Target Business Date	Activity
~~April 30~~March 1	Form 1 is posted by ~~The~~ the ERO* with all selected events for the operating year for BA usage~~reviews candidate frequency events and selects frequency events for the first quarter (December to February)~~.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Rationale

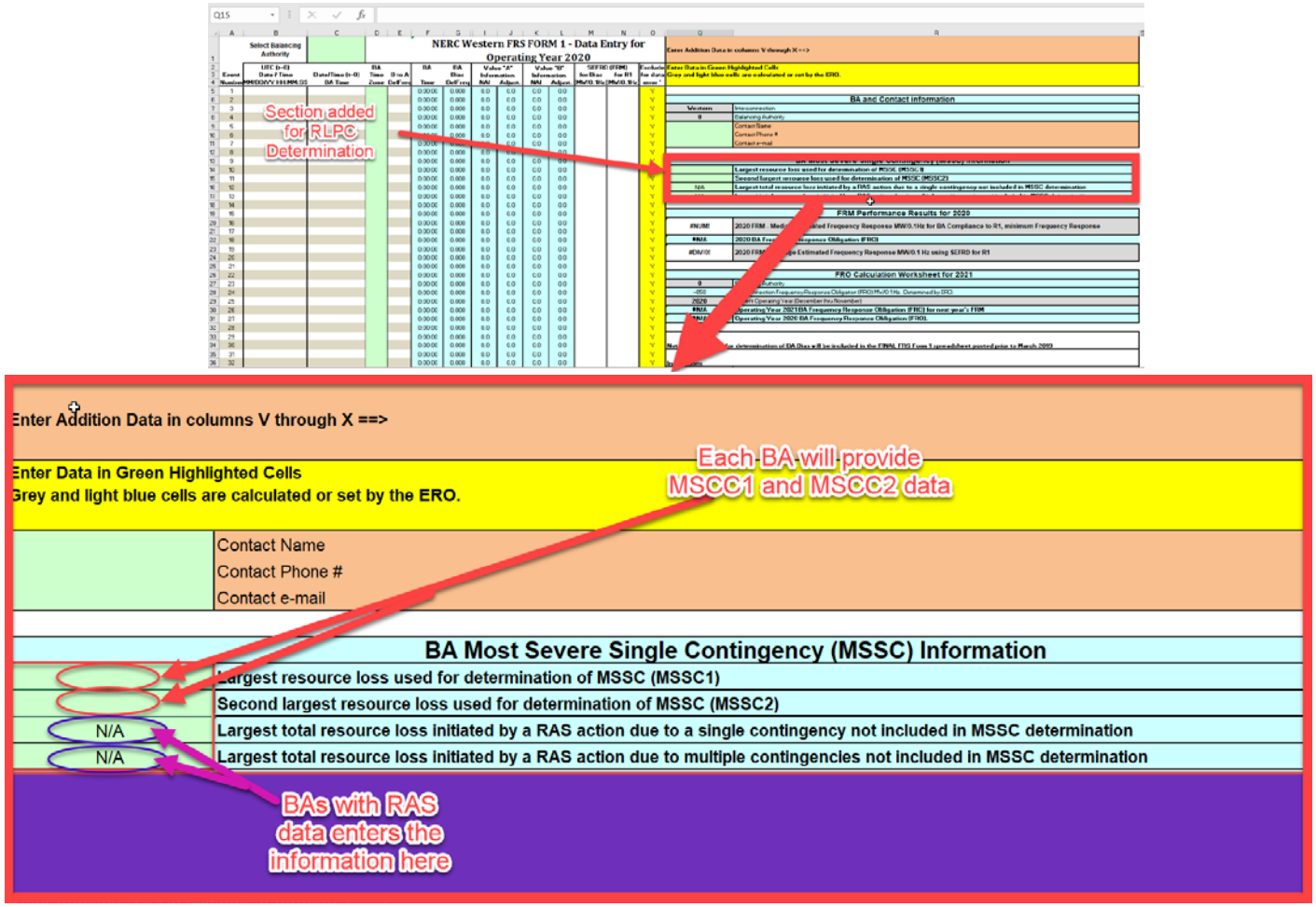
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

Modification to *FRS Form 1*

For determination of Resource Loss Protection Criteria (RLPC), each Balancing Authority (BA) will provide data for the determination of the RLPC. In addition to the current practice of providing their frequency response sampling for all four quarters and their Frequency Bias Setting (FBS) calculation, each BA shall provide requested information regarding determination of Most Severe Single Contingencies (MSCC) and resource loss due to Remedial Action Scheme (RAS) actions. To facilitate the collection of data, the *FRS Form 1* has been modified with the addition of the following field:



SDT Comments:

Background and Explanation (*Not part of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard document*)

The objectives of the additions to the BAL-003 process document are to:

- Provide a supportable process to address the intent of the B-C ratio and the analysis report
- Streamline the administrative support behind BAL-003, possible examples include
  - Reduce time pressure in getting IFROs and Bias values out
  - Only generate a full new analysis report to determine IFRO when triggered by a decline in performance from base year, otherwise a summary report could be developed and reference the last full report.
- Technically defensible replacement for the 4500 MW basis for the East as well as an on-off ramp for new credible contingencies in any Interconnection.
- While encouraging improvement, preserve reliability at the level when the standard was adopted
- Allow learning and minor changes to administrative processes without opening the standard
  - Characteristics of response may change (fewer events under current selection process if performance improves)
  - Forms improvement
- State of Reliability Report indicators to track reliability
  - Rate of Change of Frequency (RoCoF)/GW loss
  - Normalized M-4
    - Regression analyzed to correct for starting frequency and resource loss size
    - Expressed as Beta per GW loss

Below is an example of how the IFROs could be posted along with other balancing parameters.

Measure	East	West	Texas	Quebec	Notes
Epsilon 1	18mHz	22.8mHz	30mHz	21mHz	Parameter that sets CPS1 and BAAL
Balancing Authority ACE Limit	-700%	-700%	-700%	-700%	BAL-001-2 R2
Reportable Balancing Contingency Event	900MW	400MW	800MW	500MW	NERC Glossary
Interconnection Frequency Response Obligation (2019)	-1002	-840	-286	-179	(MW/0.1Hz)
Interconnection Frequency Response Obligation (2020)	-1120	-840	-286	-179	(MW/0.1Hz)

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A Procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO shall post the suggested modification for a 45-day formal comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with FERC for informational purposes.

Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used by Balancing Authorities (BA) to calculate their Frequency Response to determine:

- Whether the BA met its Frequency Response Obligation, and
- An appropriate fixed Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS frequency excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the Frequency Response Measure (FRM) calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining FRS compliance. This is described later.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 12 seconds following the start of the excursion.

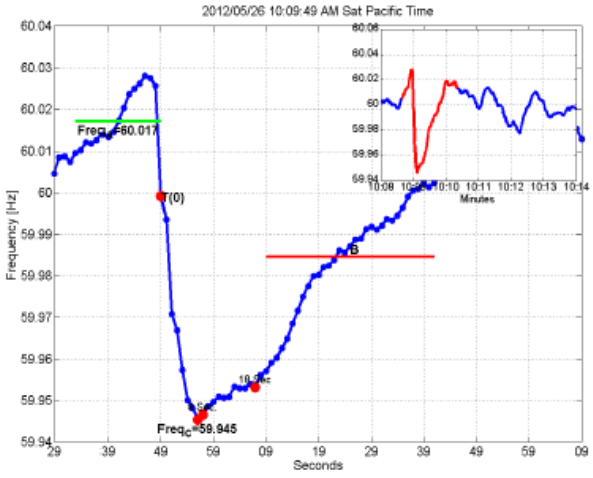
Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

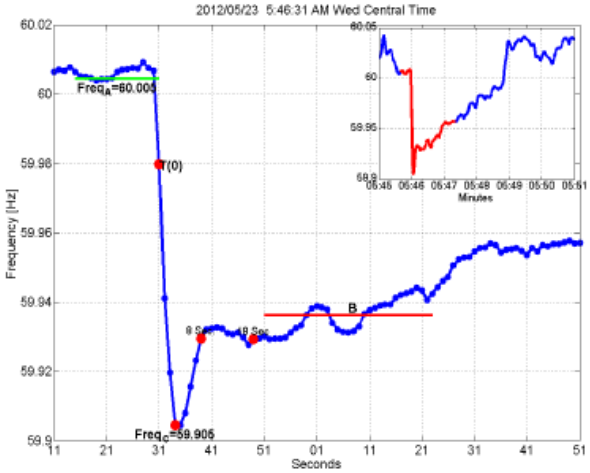
Table 1: Interconnection Frequency Excursion Threshold Values

b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.

c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.





5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.

6. Frequency excursion events occurring during periods:

   (i) when large interchange schedule ramping or load change is happening, or

   (ii) within 5 minutes of the top of the hour,

   will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion *e*vents occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
    a. From the same event quarter of the year.
    b. From an adjacent month.
    c. From a similar load season in the year (shoulder vs. summer/winter)
    d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24 month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of BAL-003-1. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Monthly

Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".

Quarterly

The monthly event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard",* events will be selected to populate the FRS Form 1 for each Interconnection.

The Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS' Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.

The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-1, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each interconnection. In the first year, the minimum Frequency Bias Setting for each interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT*	N/A
HQ*	N/A

Table 2. Frequency Bias Setting Minimums

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural Frequency Response by more (in absolute value) than 0.2 percentage points of peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Interconnection Frequency Response Obligation (IFRO)

The default IFRO listed in Table 1 is based on the Resource Loss Protection Criteria (RLPC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RLPC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

SDT Comments:

Assuming the industry agrees, this language will be moved to the *Procedure Document*, as it will no longer exist in Attachment A of BAL-003-2. The drafting team recommends removing these procedural steps from Attachment A as they are subject to engineering studies and modifications that can be revised outside of the standards development process.

NOTE: Although the language would no longer be included in the standard under the proposed revisions, this calculation process would remain subject to stakeholder comment on any revisions, and it would remain subject to Board approval/adoption and would be filed with FERC for informational purposes.

The process to modify this document is defined in the first paragraph of this document and states, *"This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A Procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO shall post the suggested modification for a 45-day formal comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with FERC for informational purposes."* The process to modify this document continues in concert with the *Rules of Procedure.*

The information shown here would be modified under the standards drafting team's proposals in the other posted documents in this informal posting. When feedback is received from industry, the standards drafting team will evaluate and modify this section based on comments received.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Starting Frequency (F_{Start})	59.974	59.976	59.963	59.972	Hz
Prevailing UFLS First Step	59.5*	59.5	59.3	58.5	Hz
Base Delta Frequency (DF_{Base})	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R	1.000	1.625	1.377	1.550	
Delta Frequency (DF_{CBR})	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}	0.018	N/A	N/A	N/A	Hz
Max. Delta Frequency (MDF)	0.449	0.291	0.473	0.949	
Resource Contingency Criteria (RCC)	4,500	2,740	2,750	1,700	MW
Credit for Load Resources (CLR)		300	1,400**		MW
IFRO	-1,002	-840	-286	-179	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\text{FRO}_{\text{BA}} = \text{IFRO} \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Interconnection Frequency Response Obligation Methodology

This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).

The following are the formulae that comprise the calculation of the IFROs.

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARCC = RCC - CLR$$

$$IFRO = \frac{ARCC}{10 * MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- CC_{Adj} is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of the Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RCC is the resource contingency criteria.
- CLR is the credit for load resources.
- ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Adjustments to Interconnection Frequency Response Obligations (IFRO)

Similar to the Control Performance Standard, BAL-003 is intended to be tunable, such that if performance degrades or characteristics of an Interconnection change, the IFRO adapts. Information from NERC's annual State of Reliability Report is used to determine if a detailed analysis is needed or if the IFRO needs to be increased. Information for the base year of BAL-003 is outlined in the table below.

Interconnection	Eastern	Western	ERCOT	HQ
Interconnection Median Beta	2,368.6	1,400.0	752.0	543.8
M-4 Point C	59.956	59.918	59.868	59.487
Resource Loss Protection Criteria (RLPC)	4,500	2,740	2,750	1,700
Credit for Load		300	1,400[1]	
IFRO	-1002	-840	-286	-179

Base Year (2016) Data for BAL-003-1

Supporting Annual Frequency Response Analysis

The ERO will review frequency response performance as part of its annual State of Reliability Report analysis. If Operating Year Beta remains above the base year performance, no additional review is necessary. If Operating Year Beta for an Interconnection drops below the BAL-003 base year (currently 2016), a more detailed assessment will be performed to determine if changes are needed to the IFRO. Due to expected variation in sampling and performance, as long as performance remains within 10% of base year performance, no changes in FRO are needed.

If a detailed frequency response analysis is performed, it will be posted on the ERO website.

Changes in Resource Loss Protection Criteria (RLPC)

The default RLPC for an Interconnection will be the sum of the two Most Severe Single Contingencies (MSSC) within the Interconnection. The ERO will annually verify the two largest resources in each Interconnection. If a new RLPC is identified for an Interconnection, there will be a proportional change in IFRO. For example, if a network change in WECC resulted in a 3000 MW RLPC, the new obligation becomes:

[1] The Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Loss Protection Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles

-840 x (3000/2740) = -920 MW/0.1Hz

If the change is a reduction in IFRO greater than 10%, the change will be implemented over multiple years. The ERO may pause and reassess a multi-year drop in IFRO if the Interconnection's performance indicators show a statistically significant decline or an event occurs that is larger than the RLPC. The ERO will determine future steps based on analysis.

Credit for Load

Some Interconnections have contractually obligated load that trips at a setpoint above the first step of UFLS. The ERO will annually review changes in the contractual obligation amount and will adjust the credit as appropriate.

As part of its annual analysis, the ERO will confirm whether there has been a material change in the amount of high set interruptible load. Changes in credit for load are not needed if the amount of contributing load has not changed by more than 5%.

Decline in Point C

If the average M-4 Point C in the State of Reliability Report declines below the base year, ERO will as part of its annual analysis determine whether the decline in performance is due to a decline in frequency response or due to other factors (e.g. balancing events not associated generation trips, decline in inertia, increased ramping obligations).

If the review shows the decline in Point C is due to other factors, the issue will be referred to the appropriate stakeholder committee(s).

If the review shows the decline in Point C is likely due to a decline in Frequency Response, the ERO will determine if the IFRO needs adjustment.

Posting and Communicating IFRO Changes

While unofficial, NERC will notify Balancing Authorities if it appears there may be IFRO increases in an Interconnection when it provides Balancing Authorities the final FRS Forms for the year. Once analysis is complete, NERC will post current and any upcoming changes in IFRO on its website and provide official notice to Balancing Authorities at the same time as Bias Setting notifications are transmitted.

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Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 event identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. Previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases. A quantitative approach to selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatt (MW) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control Area (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal

The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

- Each BA shall annually determine its two largest MSSC values in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- Remedial Action Scheme (RAS) resource loss which is initiated by a single (N-1) contingency event needs to be included in this determination.
- RAS resource loss which is initiated by a multiple (N-2) contingency event needs to be included in this evaluation (RLPC cannot be lower than this value).
- Each BA then submits its two largest resource losses (MSSC1, MSSC2) used to determine its MSSC for a normal (N-0) system configuration using its FRS Form 1. The data is to include:
  - Initiating event, and
  - Megawatt (MW) loss.
- FRS Form 1 data is compiled by NERC for each Interconnection.

- For each Interconnection, the two largest single contingency (N-1) MSSC values are summed to become the Interconnection RLPC.
- If N-2 RAS resource loss for the Interconnection exceeds the RLPC calculated above, then the N-2 RAS resource loss becomes the Interconnection RLPC.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	MSSC1 = 1200 MW	MSSC2 = 1200 MW	Both MSSCs at Plant 1
BA2	MSSC1 = 1400 MW	MSSC2 = 1000 MW	Electrically separate MSSCs
BA3	MSSC1 = 1000 MW	MSSC2 = 800 MW	Electrically separate MSSCs
BA4	MSSC1 = 1500 MW (DC TIE)	MSSC2 = 500 MW	Electrically separate MSSCs

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Interconnection MSSC1 = 1500 MW	Largest MSSC of the four BA's
Interconnection MSSC2 = 1400 MW	Largest remaining MSSC of the four BA's
Interconnection RLPC = 2900 MW	Summation of two largest resource losses
Interconnection Largest N-2 event	2400 MW at BA1's Plant 1

If an N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of MSSCs will exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 MSSC1 = 1150 MW
BA1 MSSC2 = 800 MW
BA2 MSSC1 = 1380 MW
BA2 MSSC2 = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 MSSC1 = 800 MW
BA3 MSSC2 = 700 MW

In this case, the summation of the two largest MSSCs are 2760 MW. However, the N-2 RAS event results in an RAS resource loss of 2850 MW. In this case, the N-2 event exceeds the summation of the two largest single contingency events. Therefore, the RLPC is the N-2 RAS event, or 2850 MW.

North American Interconnection RPLC Values

Based on initial review, the numbers below are believed to be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
MSSC1 = 1732 MW
MSSC2 = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
MSSC1 = 1505 MW
MSSC2 = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
MSSC1 = 1375 MW
MSSC2 = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
MSSC1 = 1000 MW
MSSC2 = 1000 MW
Proposed RLPC = 2000 MW

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
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~September 2017 – November 2017~~
45-day formal comment period with additional ballot	~~January~~August 2018 – ~~February~~October 2018
10-day final ballot	~~February~~October 2018
NERC Board adoption	~~May~~November 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 and each of its Transmission Planners, 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~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~ The process may allow the ~~Planning Coordinator uses~~use of 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.~~if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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~~used in ~~accordance with its~~ operations per the 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]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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~~used in ~~its~~ operations per the 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]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

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.**~~R4. ~~Each Planning Coordinator~~and each Transmission Planner 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 (Planning Coordinator only) to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- ~~6~~4.2 The associated stability criteria used as part of determining the instability;
- ~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation;
- ~~6.4~~4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;
- 4.5 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
- 4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

~~**M6.**~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement ~~R6~~R4.

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~~R4 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.~~N/A	The Planning Coordinator or a Transmission Planner 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.~~failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner 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.~~N/A	The Planning Coordinator or a Transmission Planner 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~~provide its	The Planning Coordinator or a Transmission Planner 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

			technical ~~justification~~rationale.	Reliability Coordinator's SOL Methodology.
R3.	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.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its technical ~~justification~~rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in ~~planning assessments~~Planning Assessments are equally limiting or more limiting than ~~those used in operations~~the stability performance criteria 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~~R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5~~. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted

				Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner.

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

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
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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

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

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-32

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the ~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-32.

6. Background:

~~This~~ Reliability Standard CIP-014-2 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

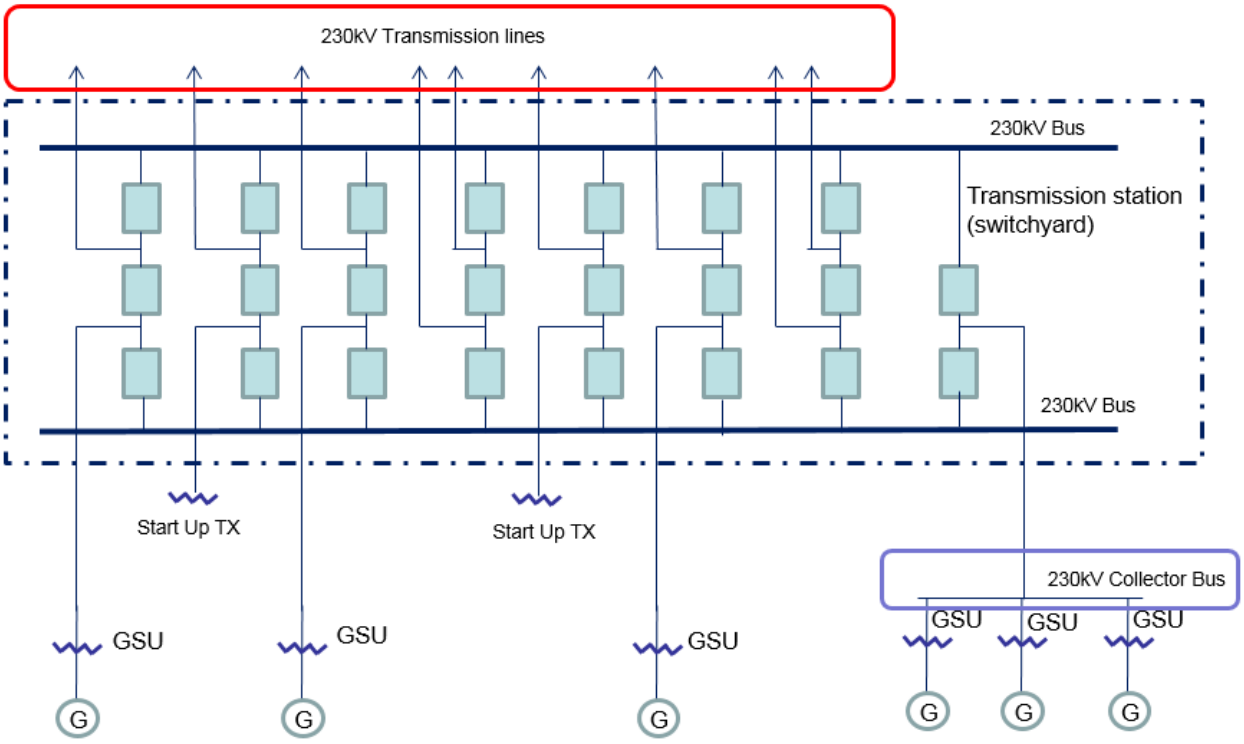
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in ~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~instability, uncontrolled separation, or Cascading. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control

center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk

assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

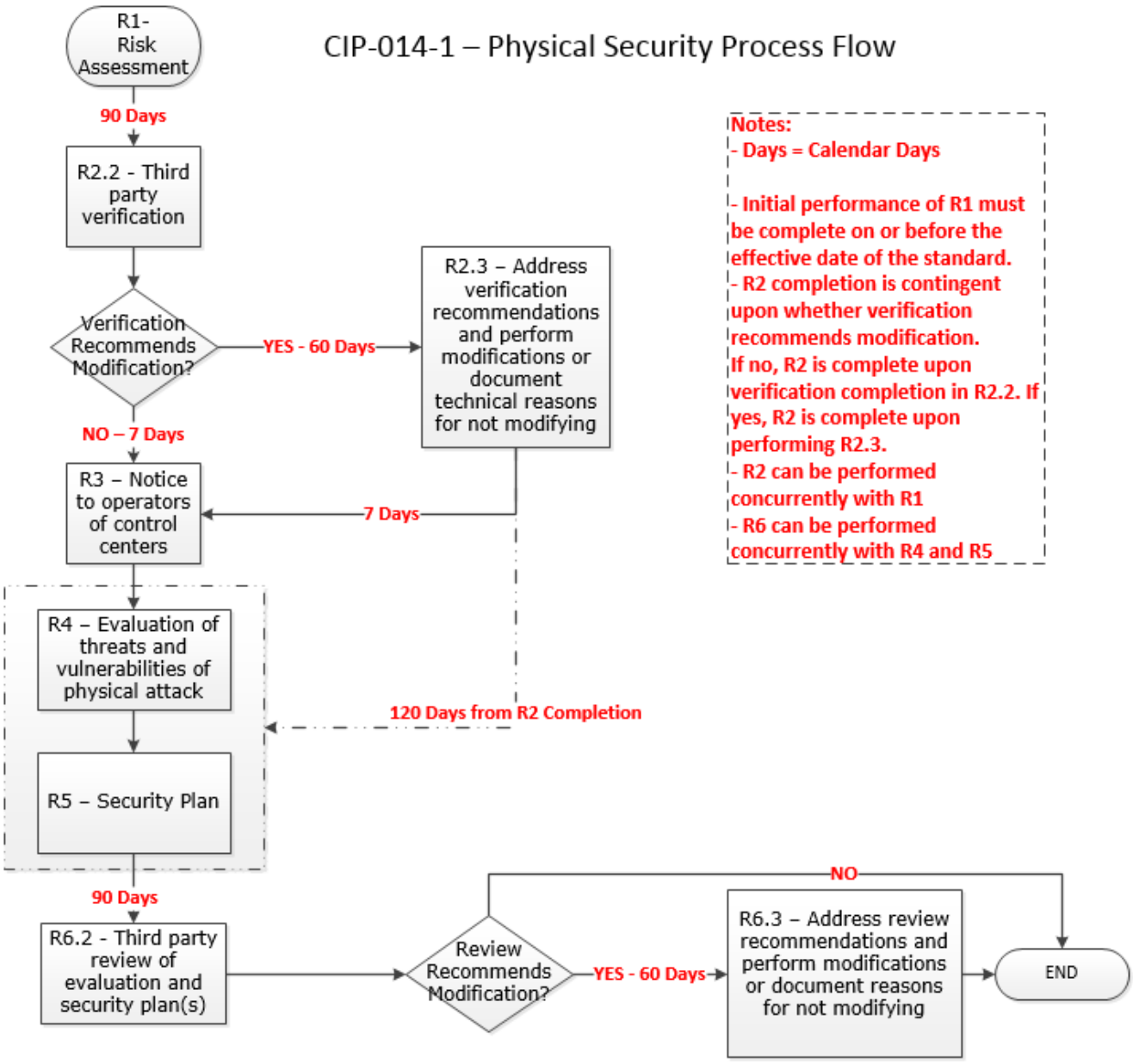
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security

plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

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
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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-54

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

   4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

   4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

   4.2.1. Each overhead transmission line operated at 200kV or higher.

   4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

   4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

   4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

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 bulk power system performance 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*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

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 defense-in-depth strategy for Rreliability Sstandards development recognizes that each requirement in a NERC Rreliability Sstandard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Sstandards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Rreliability Sstandard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

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[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use] ~~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; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:~~

~~**2.1.** An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]~~

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

~~[9] See footnote 4.~~

~~[10] See footnote 5.~~

~~2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]~~

~~2.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]~~

~~2.4.~~2.1. ~~An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

M2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)~~

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the

~~[11] See footnote 6.~~
~~[12] *Id.*~~

~~[13] *Id.*~~

associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

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.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

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 applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

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. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability,

Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per

the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW*

				• *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~*A fall-in from inside the active transmission line ROW*~~ • ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~ • ~~*A grow-in*~~
R3.		The responsible entity has maintenance strategies or documented procedures or	The responsible entity has maintenance strategies or documented procedures or	The responsible entity does not have any maintenance strategies or documented

		processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice

	line, line miles or kilometers, etc.)	units of choice - circuit, pole line, line miles or kilometers, etc.).	units of choice - circuit, pole line, line miles or kilometers, etc.).	- circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New

2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[20] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[21] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

[+] Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[23] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators may designate lines below 200 kV-, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, ~~to become elements of an IROL or Major WECC Transfer Path~~ in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC Transfer Path~~ may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an ~~IROL~~ identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the ~~S~~standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer Path~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~pursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths~~.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~that is an element of an IROL or a Major WECC Transfer Path~~ is a greater risk to the interconnected electric transmission system than applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such. Applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence

of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

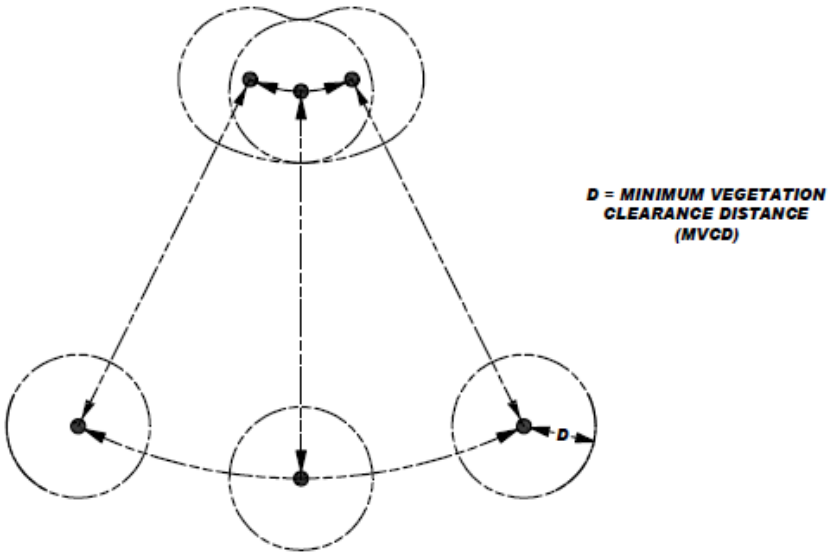


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be

documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is

still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	**(AC) Max System Voltage (kV)**	**Transient Over-voltage Factor (T)**	**Clearance (ft.) Gallet (wet) @ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003 MAID (ft) @ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 ~~and R2~~:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

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
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
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[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.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ~~the applicable~~which owner-provided Facility Ratings are to be used in operations~~. The method shall address the use of common Facility Ratings between the Reliability Coordinator and~~ such that the Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. 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]*

3.1. Require that each BES bus~~es~~/station~~s~~ have an associated System Voltage Limit, unless ~~except for~~ the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations ~~that may be excluded as specified in the Reliability Coordinator's SOL Methodology~~from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect ~~the~~voltage-based Facility ~~voltage~~ Ratings;

3.3. Require that System Voltage Limits are ~~higher~~greater than or equal to in-service relay settings for under voltage load shedding ~~(UVLS) relay settings~~systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. ~~Address~~Require ~~-~~the use of common System Voltage Limits between the ~~Reliability Coordinator and the~~ Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~ and provide the method for determining the common System Voltage Limits to be used in operations;

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]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~angular~~unit stability; and

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~~stability limits are ~~identified~~determined, 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 and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. ~~;~~

~~4.6.~~4.7. State that the ~~planned~~ use of underfrequency load shedding (UFLS) ~~is~~programs and Undervoltage Load Shedding Programs are 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~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs~~).~~) for the area under study. The ~~method~~SOL Methodology shall ~~include~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. ~~The~~Specify 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~~Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. ~~Any~~Identify any additional single or multiple Contingency events or types of ~~single~~ Contingency events ~~identified~~for use in performing Operational Planning Analysis and Real-time Assessments.

~~5.2.~~5.3. Identify any additional single or multiple Contingency events or types of Contingency events 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~~Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement ~~R6 to identify the Contingencies for~~R4, to use in determining stability limits.

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, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. 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.

~~R6.~~R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~6.1.~~7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~6.2.~~7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

~~M6.~~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 R6.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs ~~it established~~ to the ~~its~~ Reliability Coordinator~~(s)~~. The method shall address the periodicity for communicating established~~of~~ SOLs ~~communication~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M7.~~M8. 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.

~~R8.~~R9. Each Reliability Coordinator shall provide its SOL Methodology ~~and any changes to the SOL Methodology prior to the effective date of the SOL Methodology,~~ to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~8.1.~~9.1. Each~~Each adjacent Reliability Coordinator within an Interconnection, and each~~ Reliability Coordinator that requests and indicates it has a reliability-related need~~;~~ within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same~~an~~ Interconnection;

~~8.1.1.~~9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

~~8.1.2.~~9.2.3. Each Transmission Operator within its Reliability Coordinator Area~~.~~; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

~~M8.~~M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts,

registered mail receipts, or postings to a secure web site with accompanying notification(s).

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 Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through ~~R8~~R9 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.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	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.
R3.	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.
R4.	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.
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.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
~~R6~~R7.	N/A	N/A	The Reliability Coordinator failed to include Part ~~6~~7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts ~~6~~7.1 and ~~6~~7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part ~~6~~7.2 (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~~7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
~~R7~~R8.	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.
~~R8~~R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~one~~three of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~two~~four or more of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1 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 Requirement R9, Part ~~8.4~~9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R9, Part 9.2 prior to the effective date 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.~~Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, 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 Requirement R9, Part ~~8.4~~9.1.

D. Regional Variances

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
4		Project 2015-09 – Adopt revisions to standard.	Revisions

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
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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 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:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. **Number:** FAC-013-32

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use~~A statement that the assessment shall respect known System Operating Limits (SOLs)~~.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning~~planning~~ Assessments~~practices~~.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available 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 Planning Coordinator 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 shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and 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.
Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 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	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

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
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
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~September 2017 – October 2017~~
45-day formal comment period with additional ballot	~~January~~August 2018 – ~~February~~October 2018
10-day final ballot	~~February~~October 2018
NERC Board ~~(Board)~~ adoption	~~May~~November 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

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). *[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 demonstrates the Reliability Coordinator established IROLs in accordance with it 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. *[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 demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its 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. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator provided its SOLs 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. *[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 demonstrates 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, the 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);

5.2.5 A description of the associated system conditions; and

5.2.6 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 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.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate that~~, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator ~~that is impacted by an IROL~~ shall ~~provide Transmission Owners and Generation Owners within its~~ use the Bulk Electric System performance criteria specified in the Reliability ~~Coordinator Area a list of Facilities owned by that entity that are critical~~Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to ~~the derivation of the IROL.~~determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~, that demonstrates the Transmission Operator and Reliability Coordinator ~~provided~~used the ~~list of Facilities~~Bulk Electric System performance criteria specified in ~~accordance with Requirement R6~~the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

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 Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through ~~R6~~R8 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.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to 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.
R2.	N/A	N/A	N/A	The Transmission Operator ~~did not~~failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but ~~did not~~failed to provide its SOLs at the periodicity at which the RC needs such	The Transmission Operator ~~did not~~failed to provide its SOLs to its Reliability Coordinator.

			information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to 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.
R5.	The Reliability Coordinator ~~did not~~failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.
R6.	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.~~A Transmission Operator or

				Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

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

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- ~~Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")~~
  - FAC-011-4 System Operating Limits Methodology for the Operations Horizon
  - FAC-014-3 Establish and Communicate System Operating Limits
  - FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

~~[*New/Modified/Retired*] Terms in the NERC Glossary of Terms~~

~~**Proposed New Definition(s):**~~
~~System Voltage Limit: The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.~~

~~Applicable Entities~~

- ~~Reliability Coordinator~~
- ~~Planning Coordinator~~
- CIP-014-2 Physical Security
- FAC-003-4 Transmission ~~Planner~~Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission ~~Operator~~Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
  - Entities with newly classified “Remedial Action Scheme” (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.
- Implementation of PRC-026-1
  - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1~~ and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and ~~term~~terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1~~ and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and ~~term~~terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, ~~and FAC-014-2~~FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and FAC-015.~~FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard 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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-32

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 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~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have

dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the 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 Transmission Owner, Generator Owner, ~~Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC |~~ RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed

the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the

potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-54

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used

exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

~~**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.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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 initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-2~~1~~**

3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

   This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

   Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

   Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

B. Requirements and Measures

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: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generatorSystem Operating Limit (SOL) or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. An Elements associated with that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular instability identified in Planning Assessmentsconstraint.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner 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.

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[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit 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

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates

Zone Timer (Cycles)	Slip Rate (Hz)
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

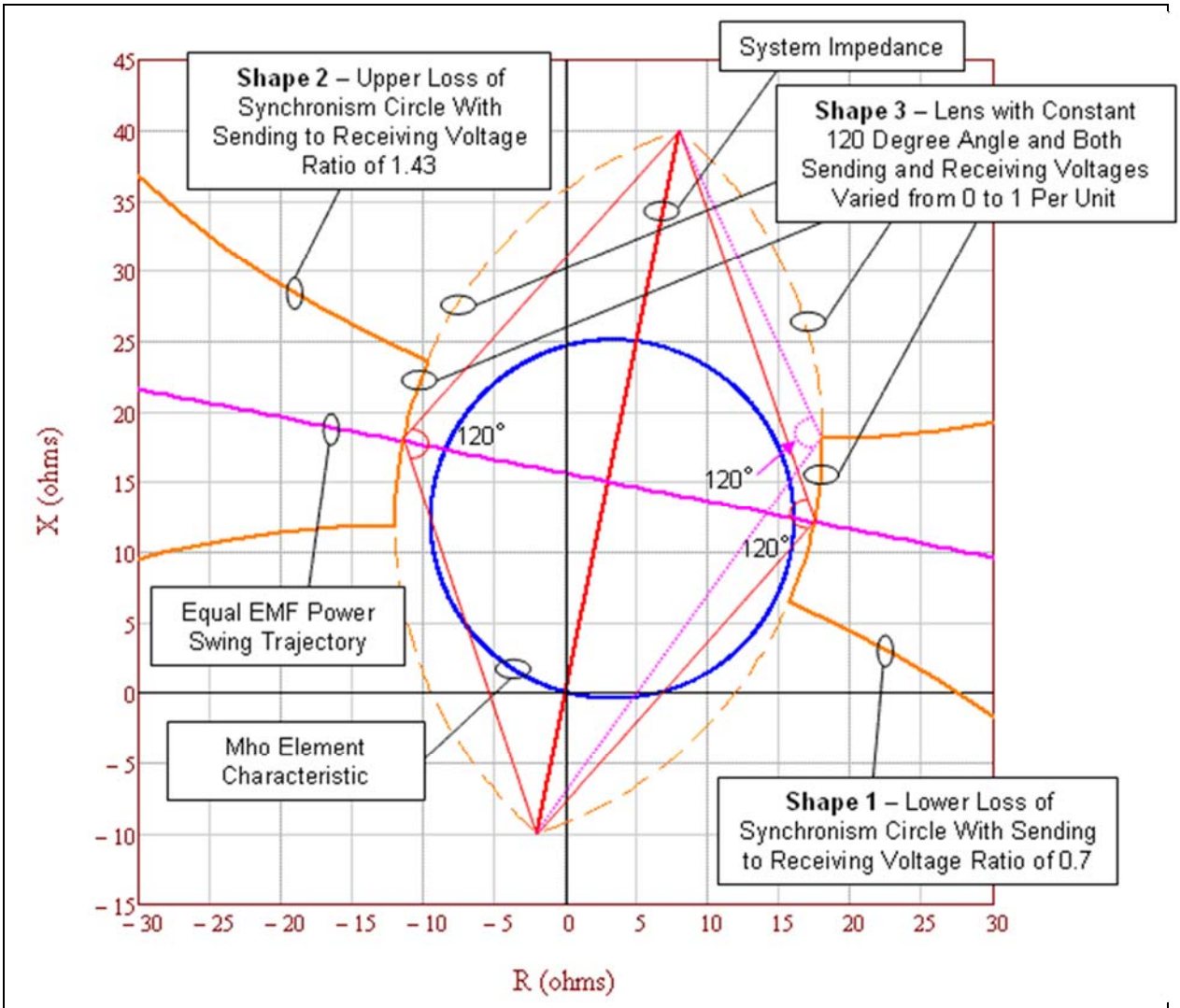

Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

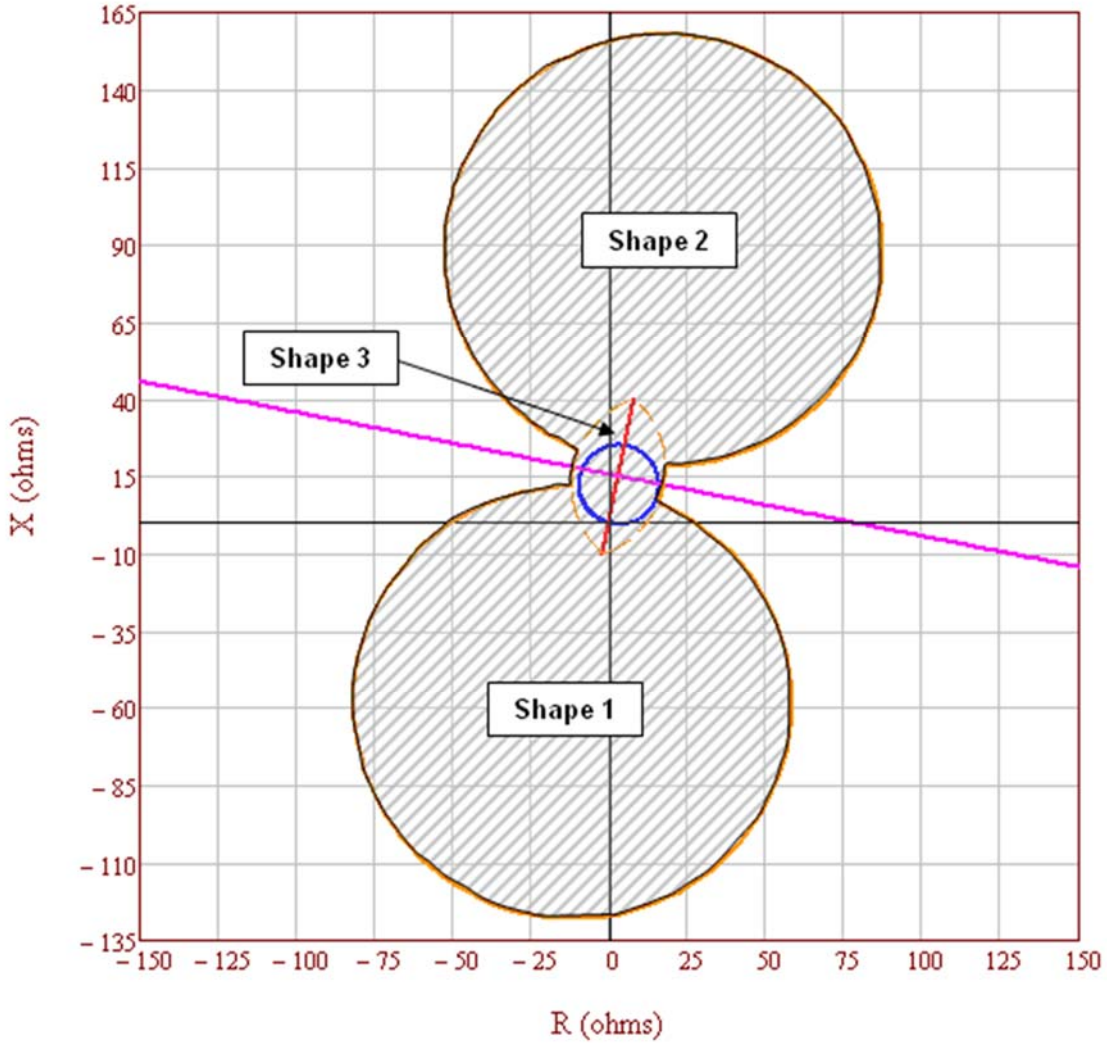

Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

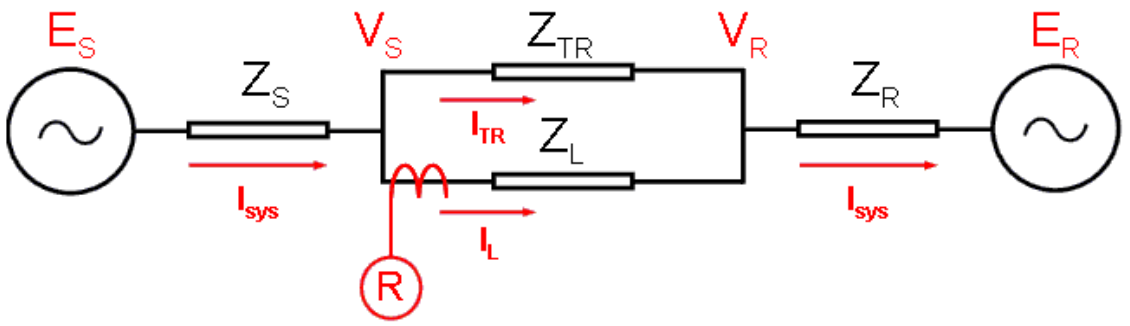

Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

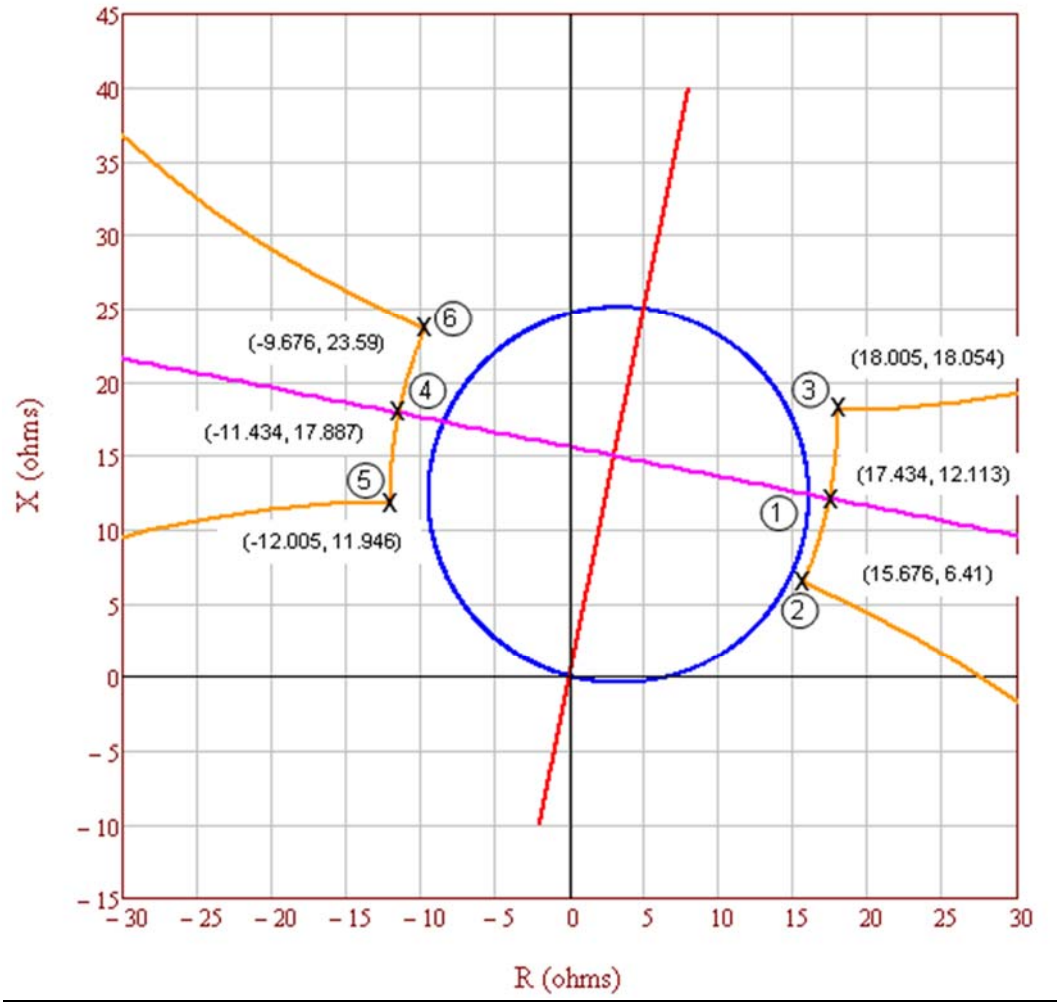

Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3° \; A \times \frac{(4 + j20) \times 10^{10} \; \Omega}{(4 + j20) \; \Omega + (4 + j20) \times 10^{10} \; \Omega}$
	$I_L = 4{,}511\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10) \; \Omega \times 4{,}511\angle 71.3° \; A]$
	$V_S = 95{,}757\angle 106.1° \; V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \; V}{4{,}511\angle 71.3° \; A}$
	$Z_{L-Relay} = 17.434 + j12.113 \; \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120° \; V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120° \; V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \; V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \; V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \; \Omega$	$Z_L = 4 + j20 \; \Omega$	$Z_R = 4 + j20 \; \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \; \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

Table 5: Example Calculation (Lens Point 4)			
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.			
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$		
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1° \, A]$		
	$V_S = 95{,}756\angle -106.1° \, V$		
The impedance seen by the relay on Z_L.			
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$		
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1° \, V}{4{,}511\angle 131.1° \, A}$		
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$		

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240° \, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 137.1° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10 \,) \, \Omega \times 3{,}854\angle 137.1° \, A]$
	$V_S = 98{,}265\angle -110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

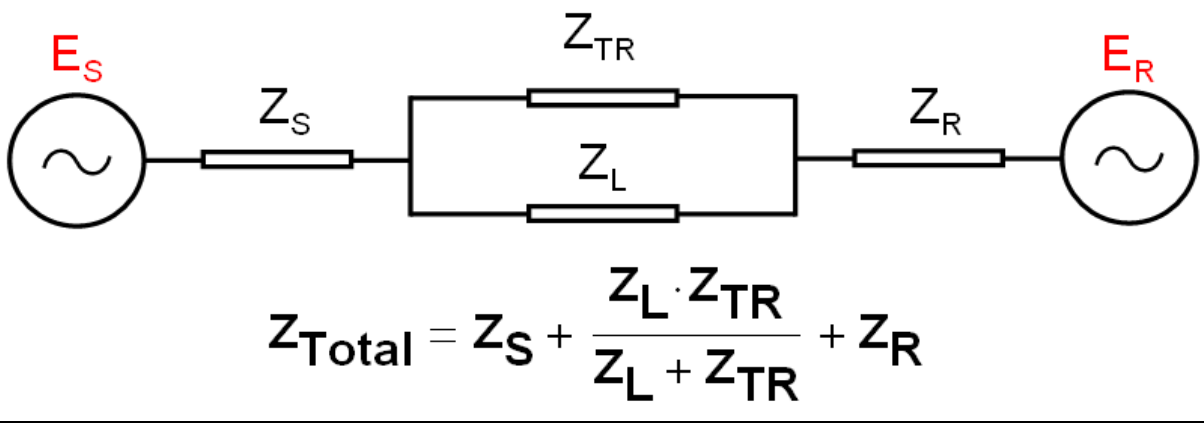

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

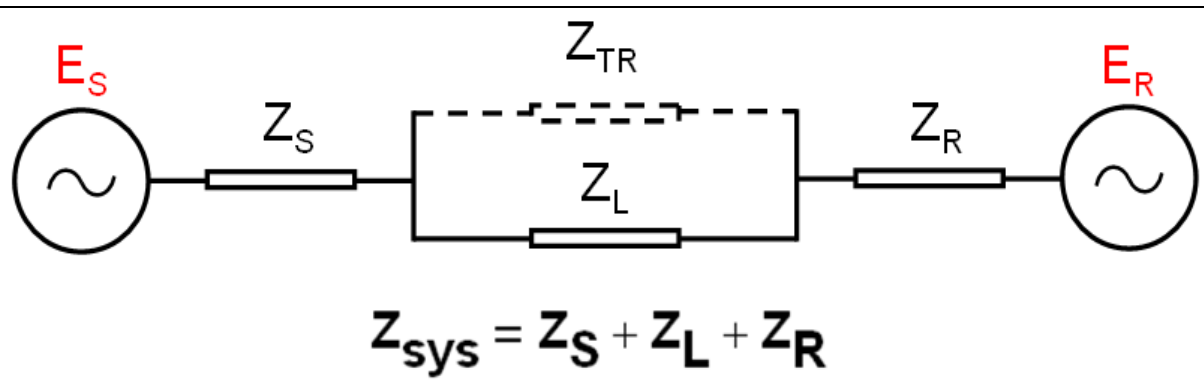

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

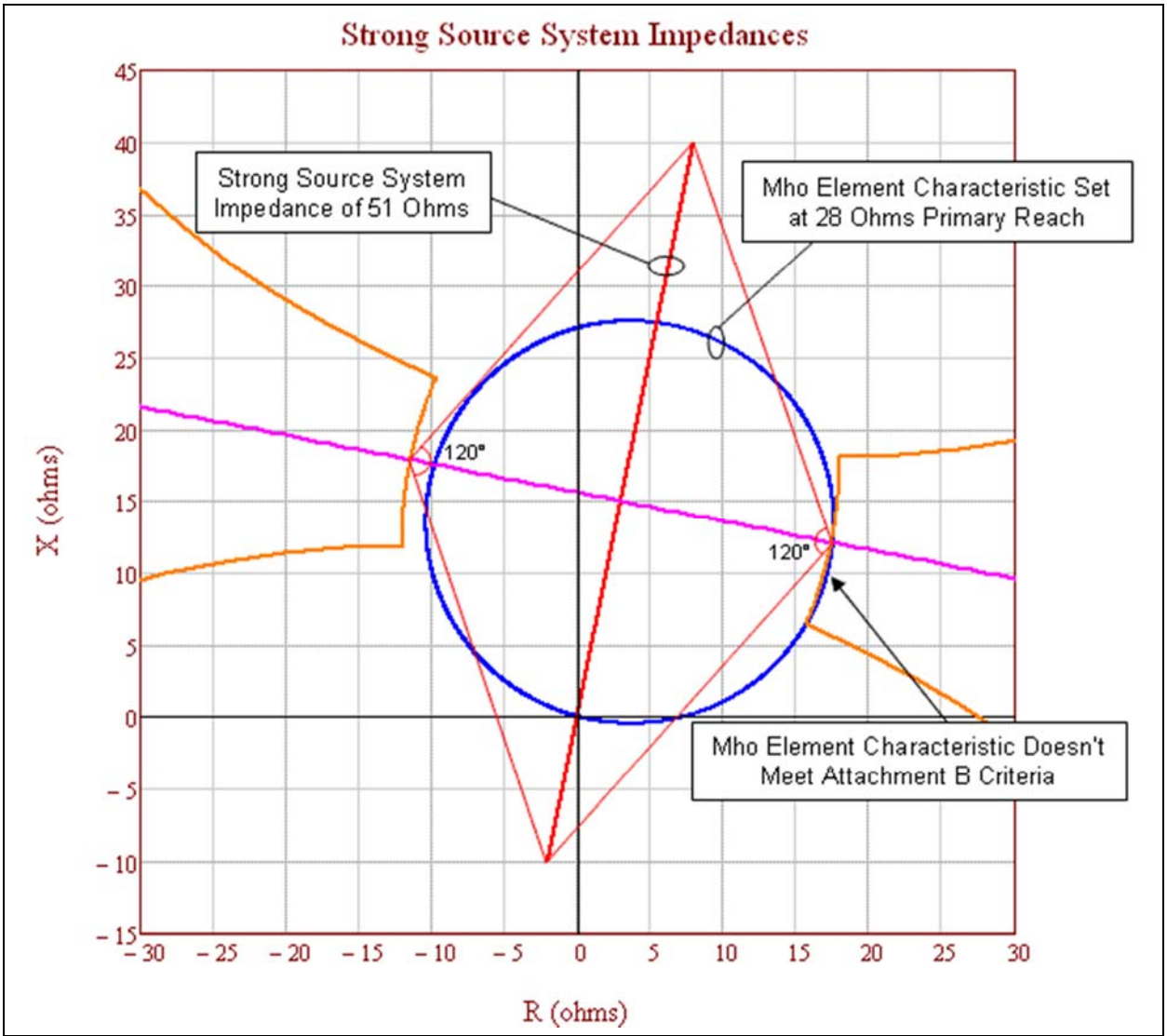

Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

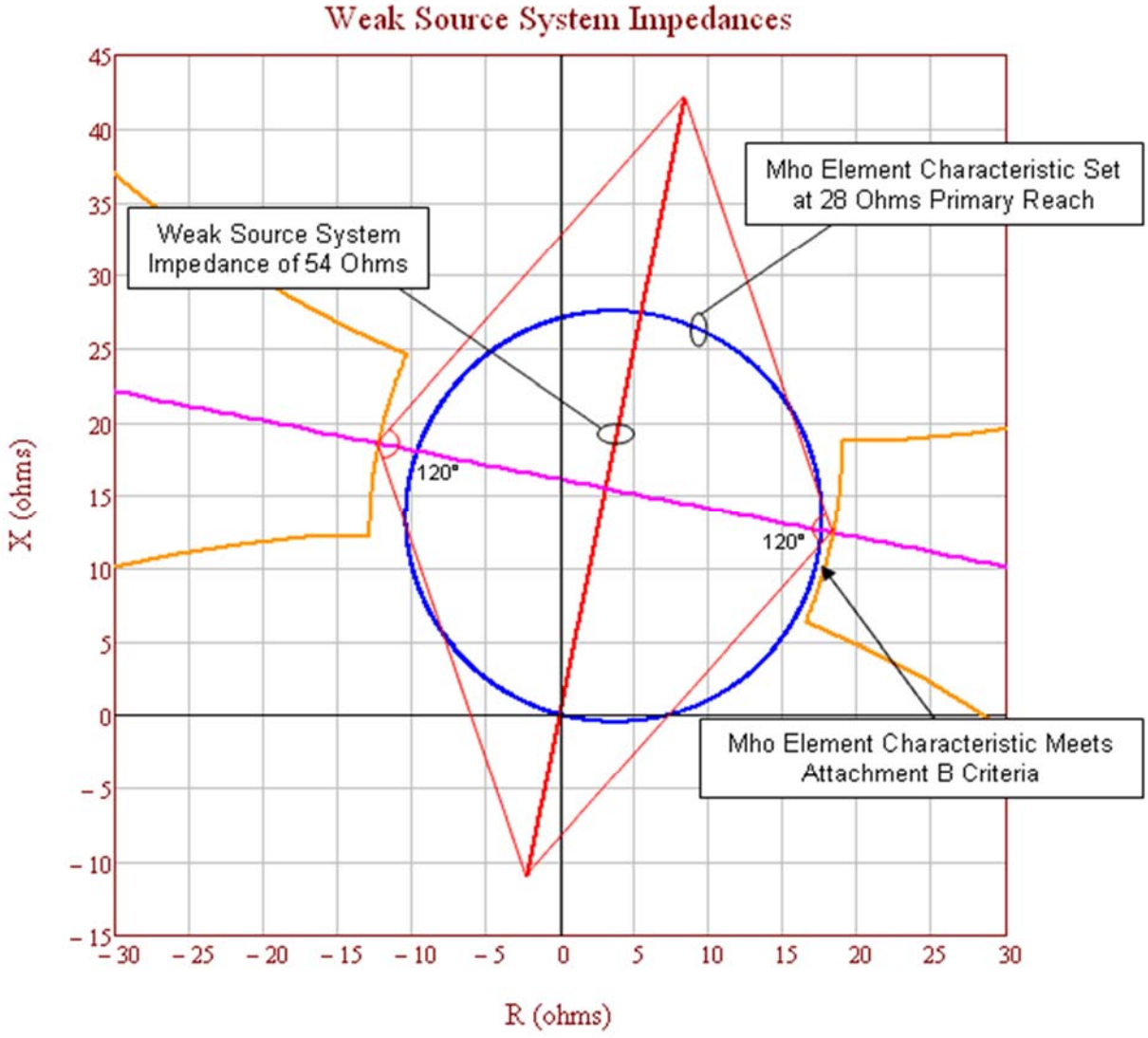

Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

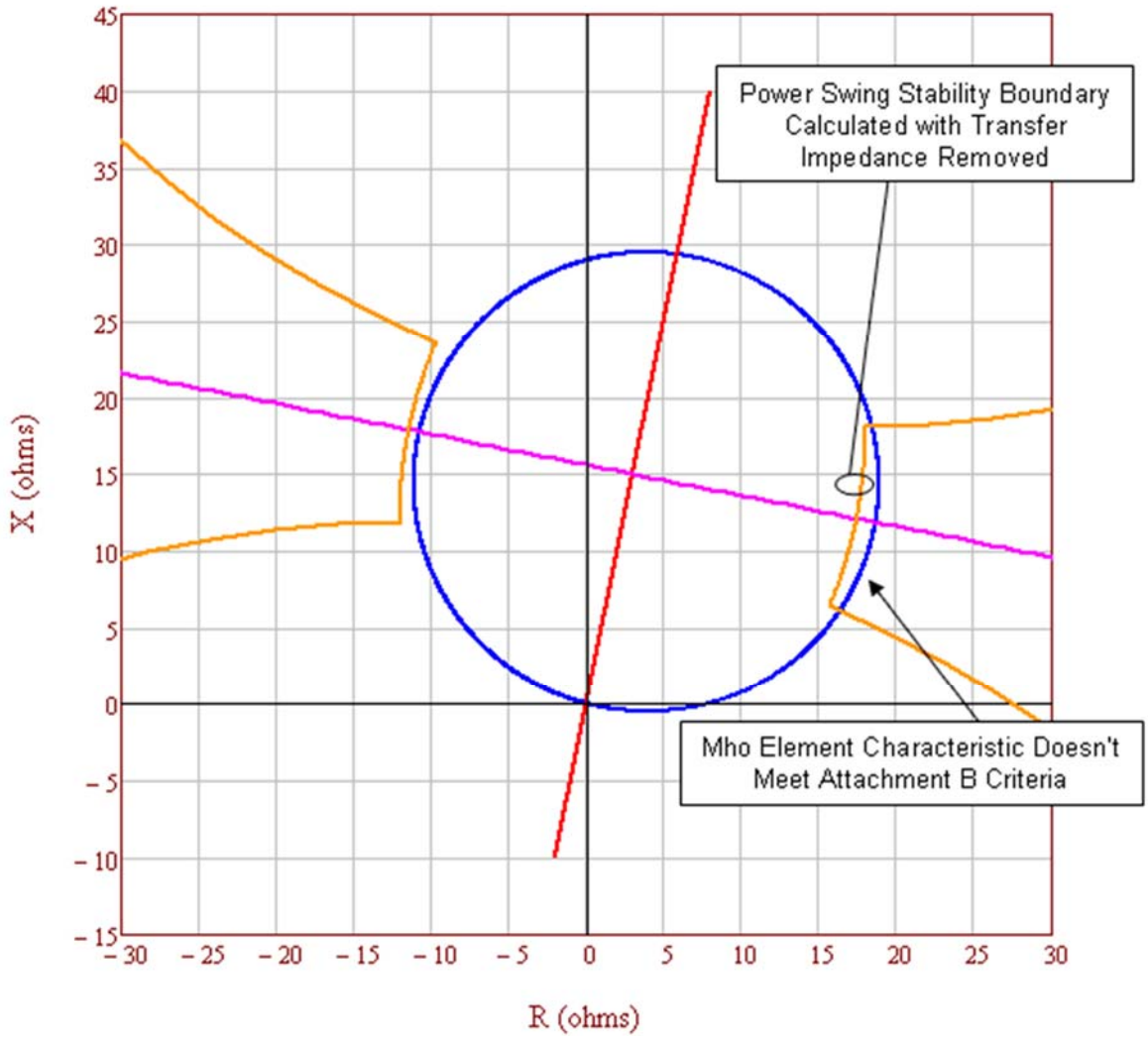

Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

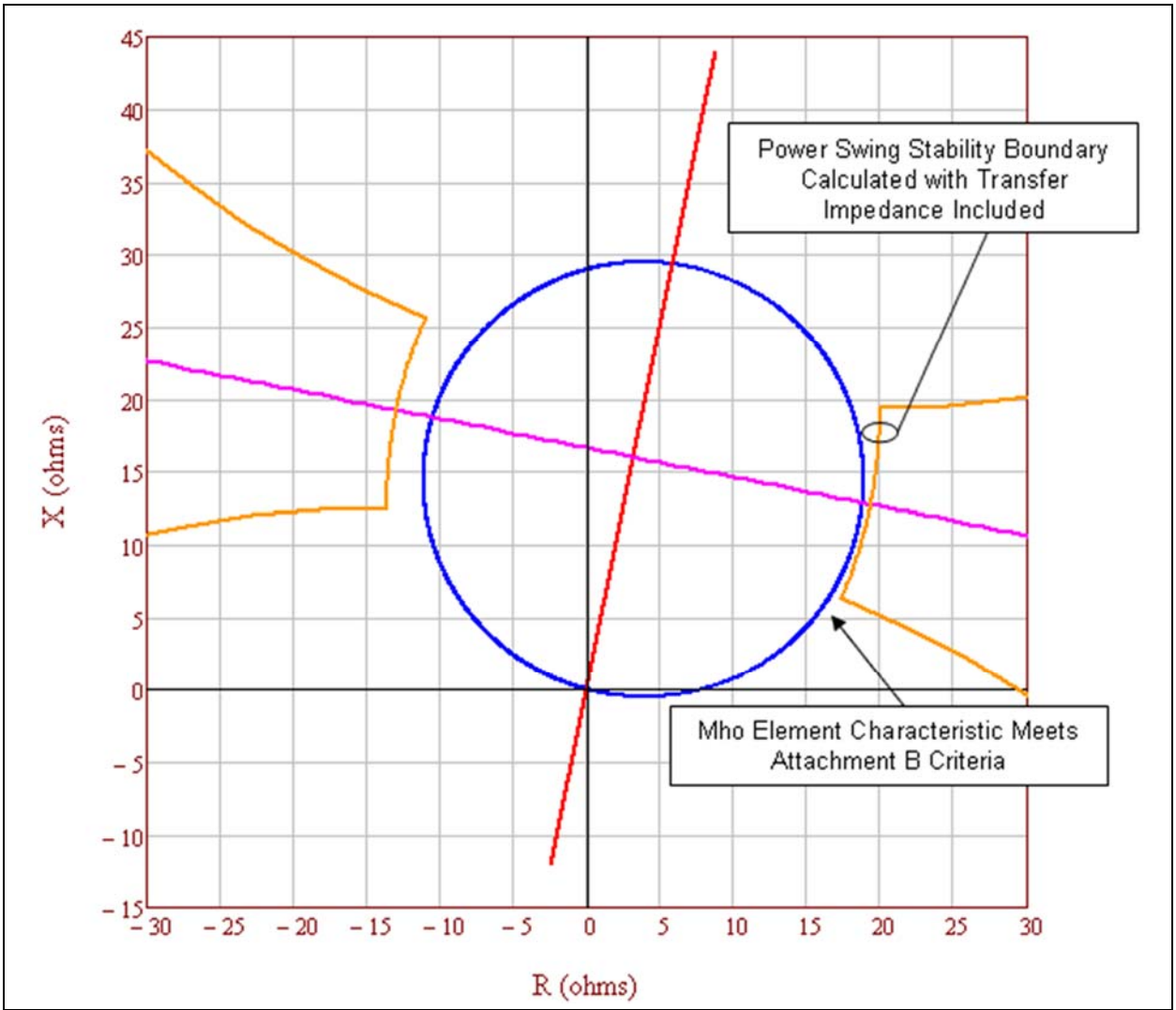

Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3° \; A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3° \; A \times \frac{(20 + j100)\;\Omega}{(4 + j20)\;\Omega + (20 + j100)\;\Omega}$
	$I_L = 4{,}027.4\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10\;\Omega) \times 4{,}833\angle 71.3° \; A]$
	$V_S = 93{,}417\angle 104.7° \; V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7° \; V}{4{,}027\angle 71.3° \; A}$
	$Z_{L-Relay} = 19.366 + j12.767\;\Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

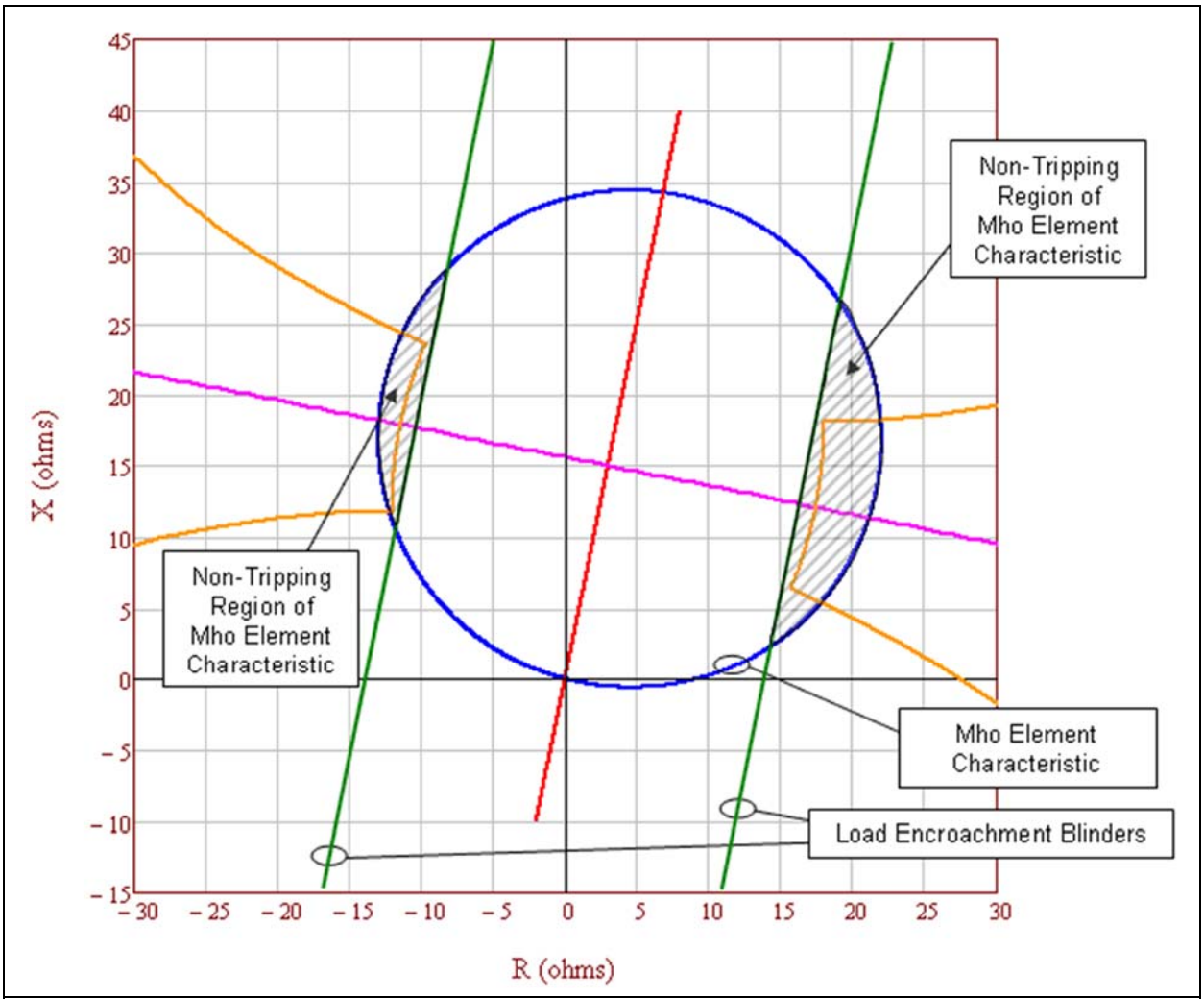

Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

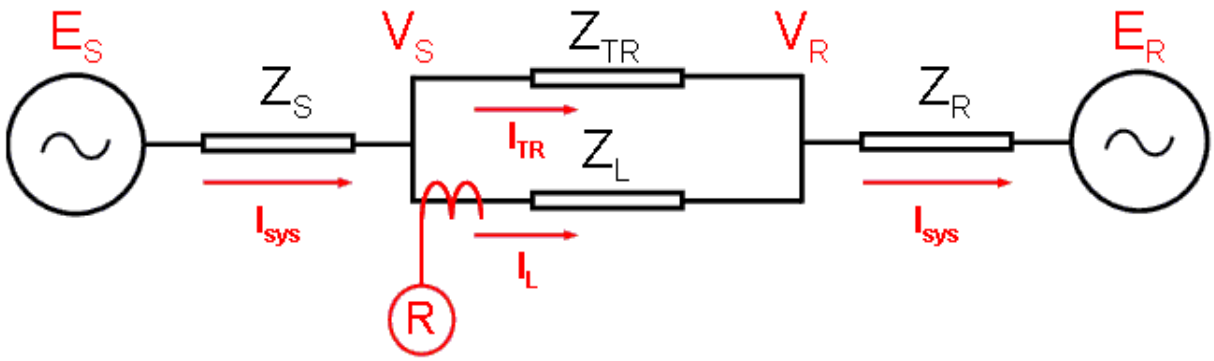

Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

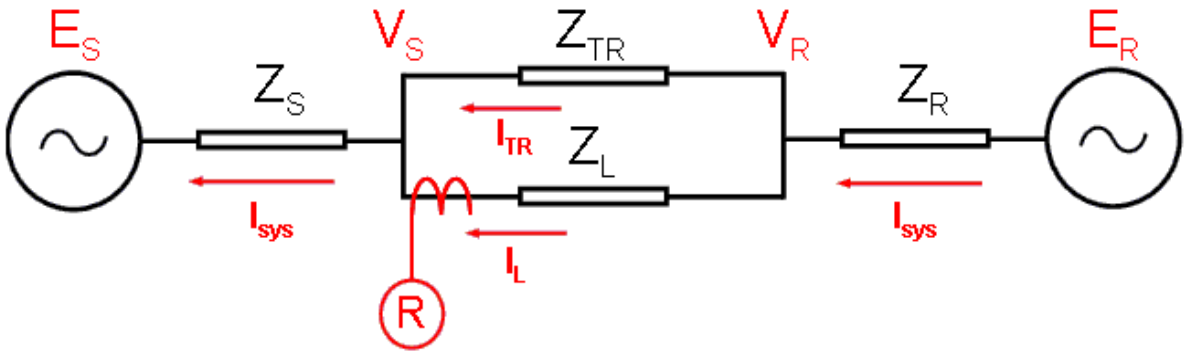

Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

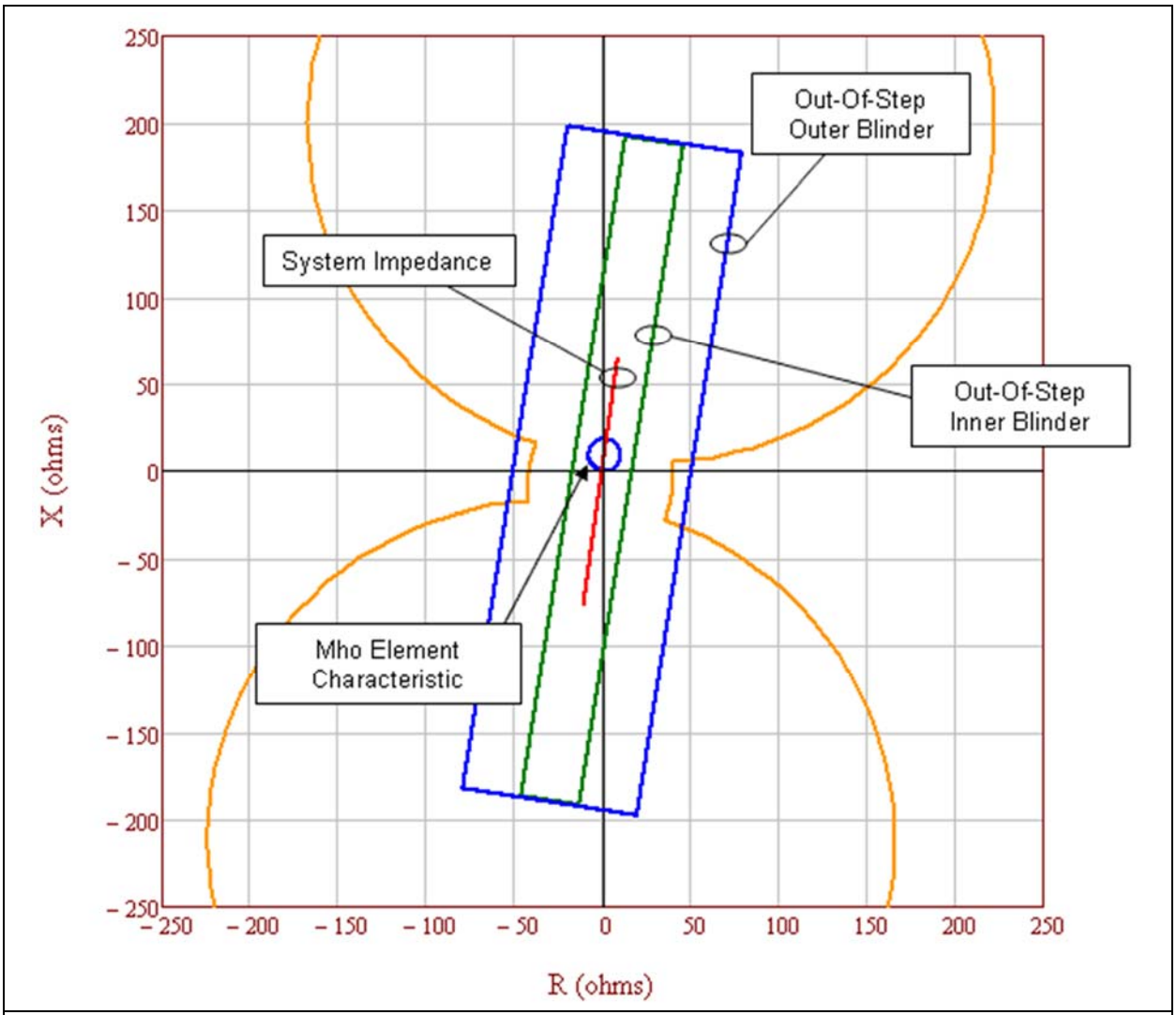

Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}} \right) \right] + \left[\frac{Z_{sys}}{N^2 - 1} \right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega} \right) \right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1} \right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

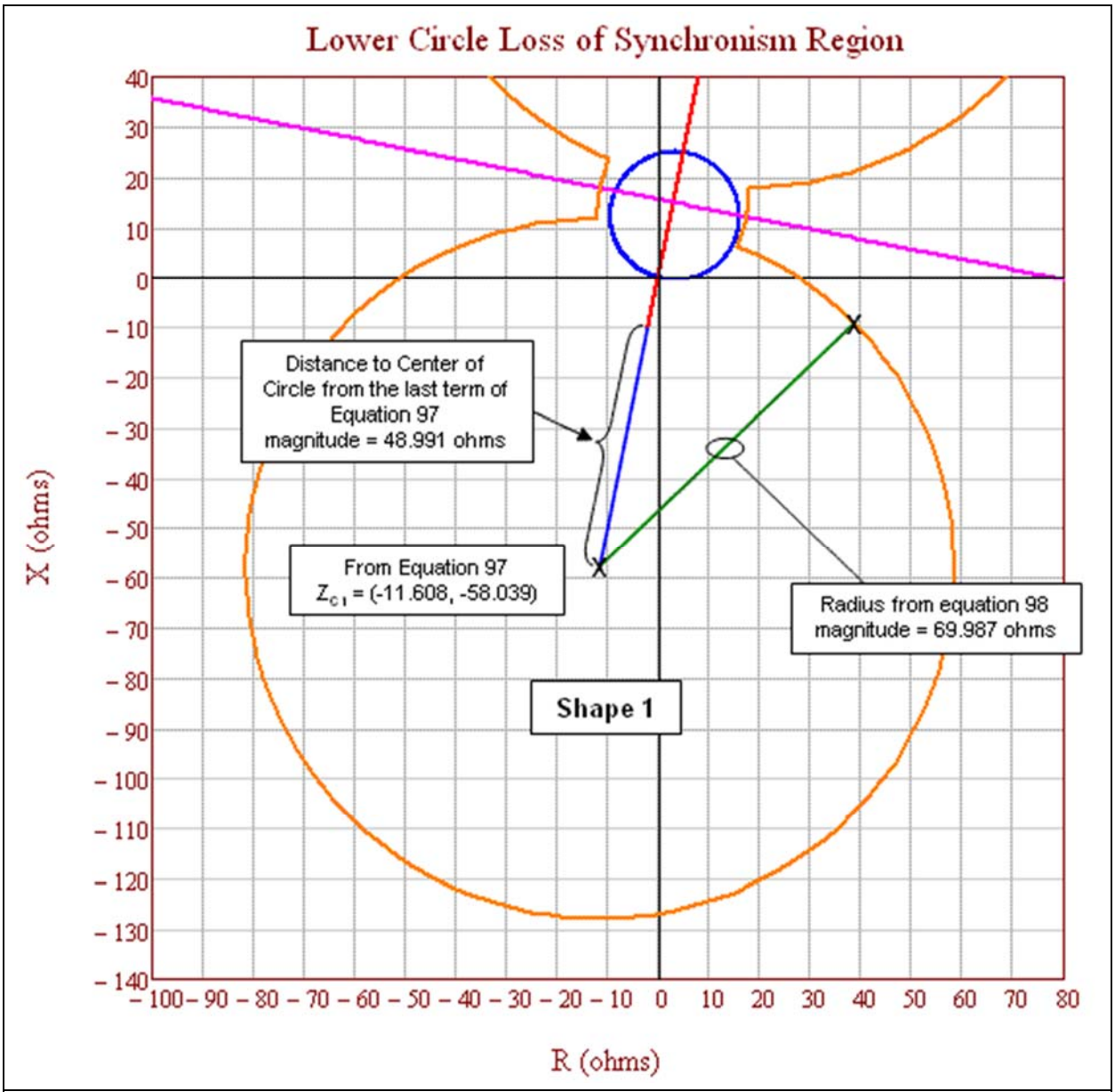

Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

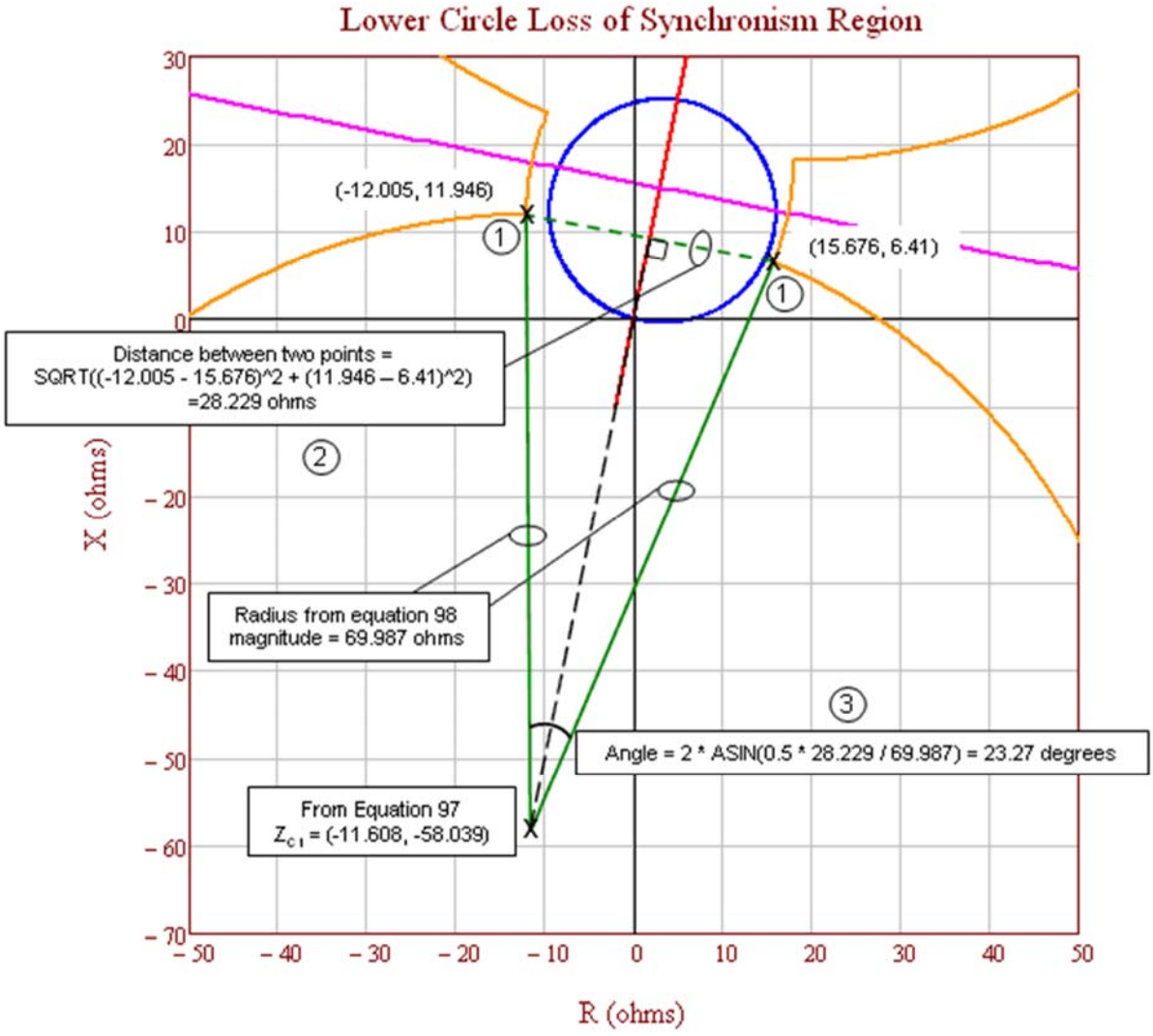

Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

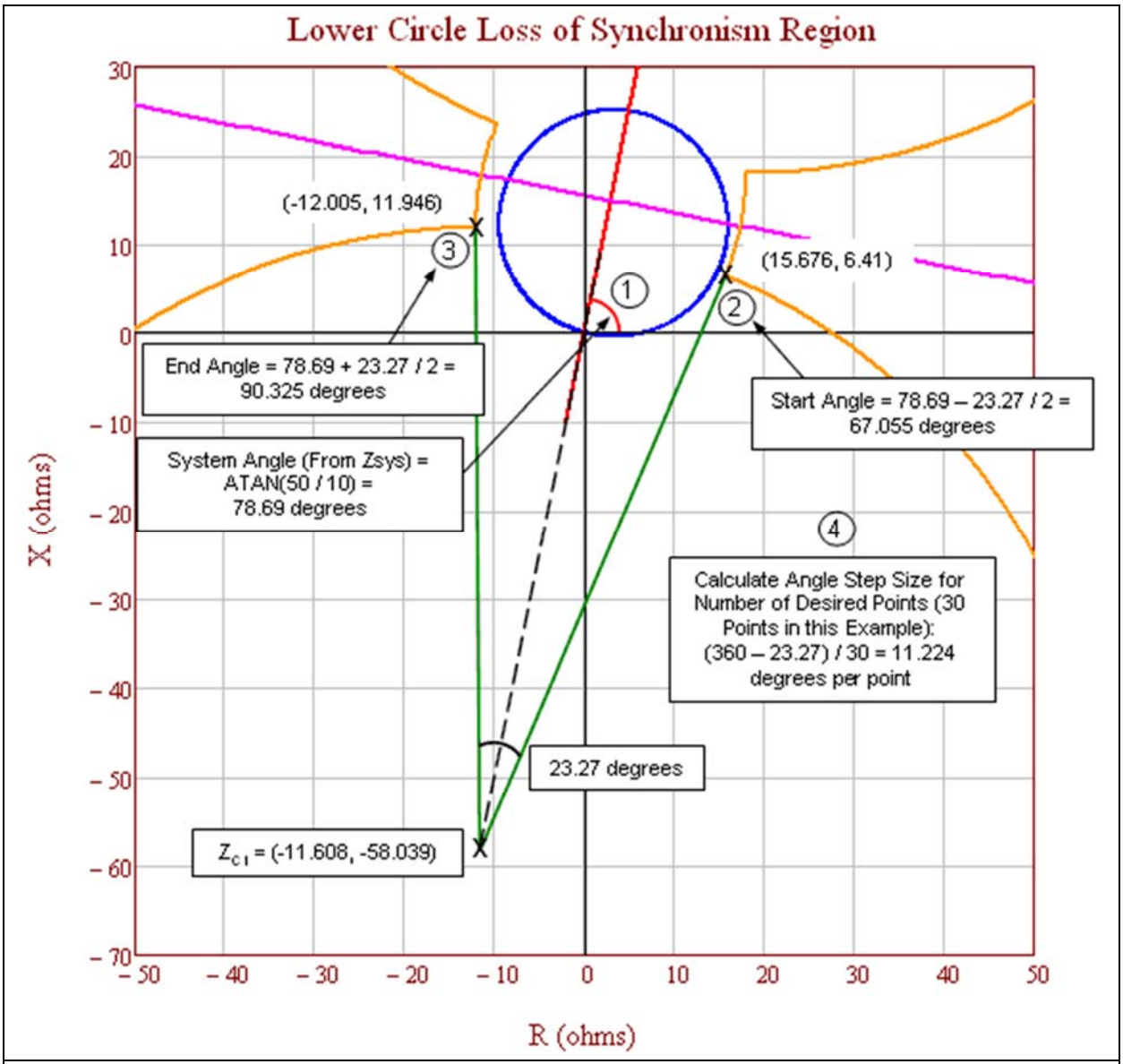

Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

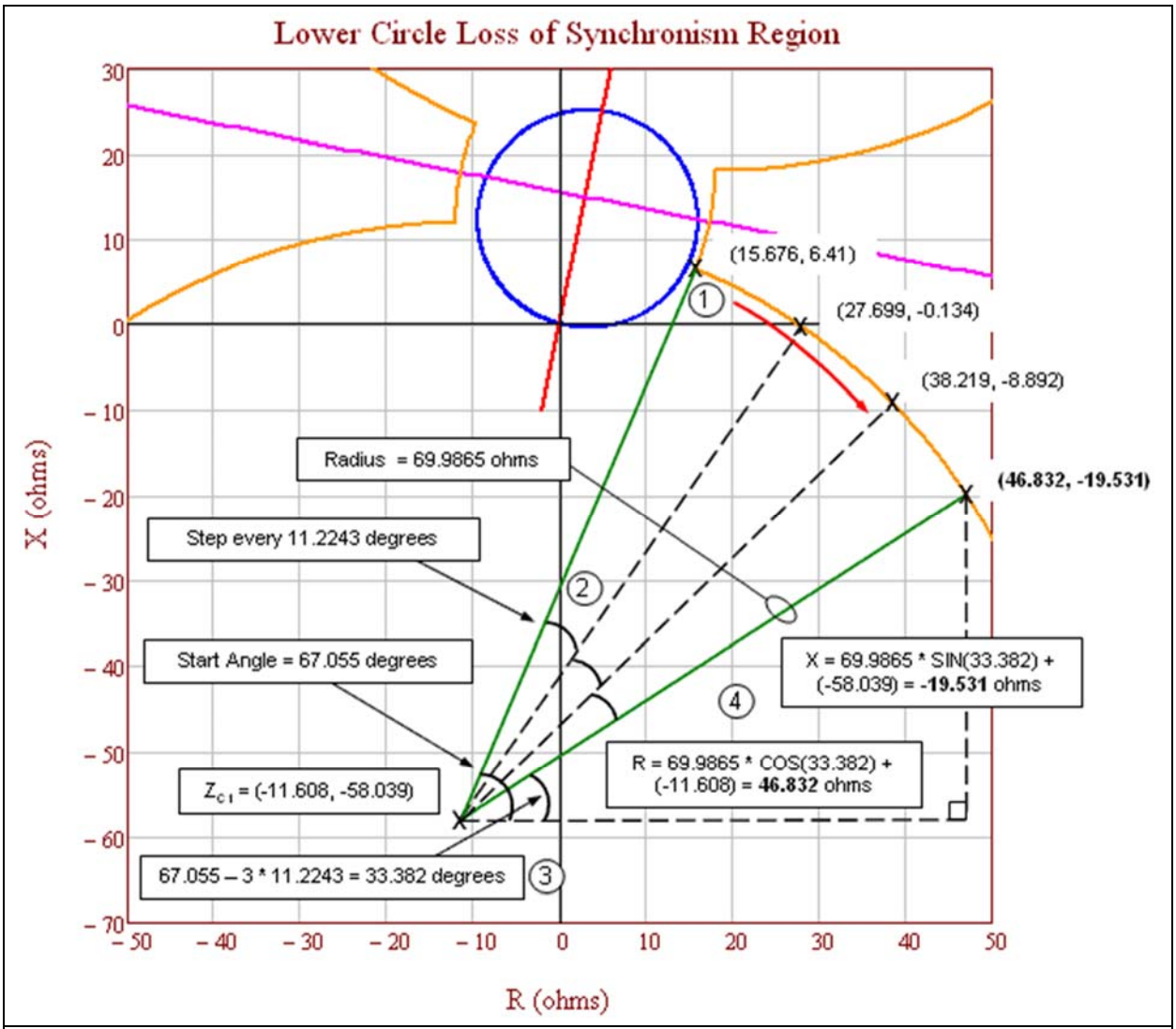

Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

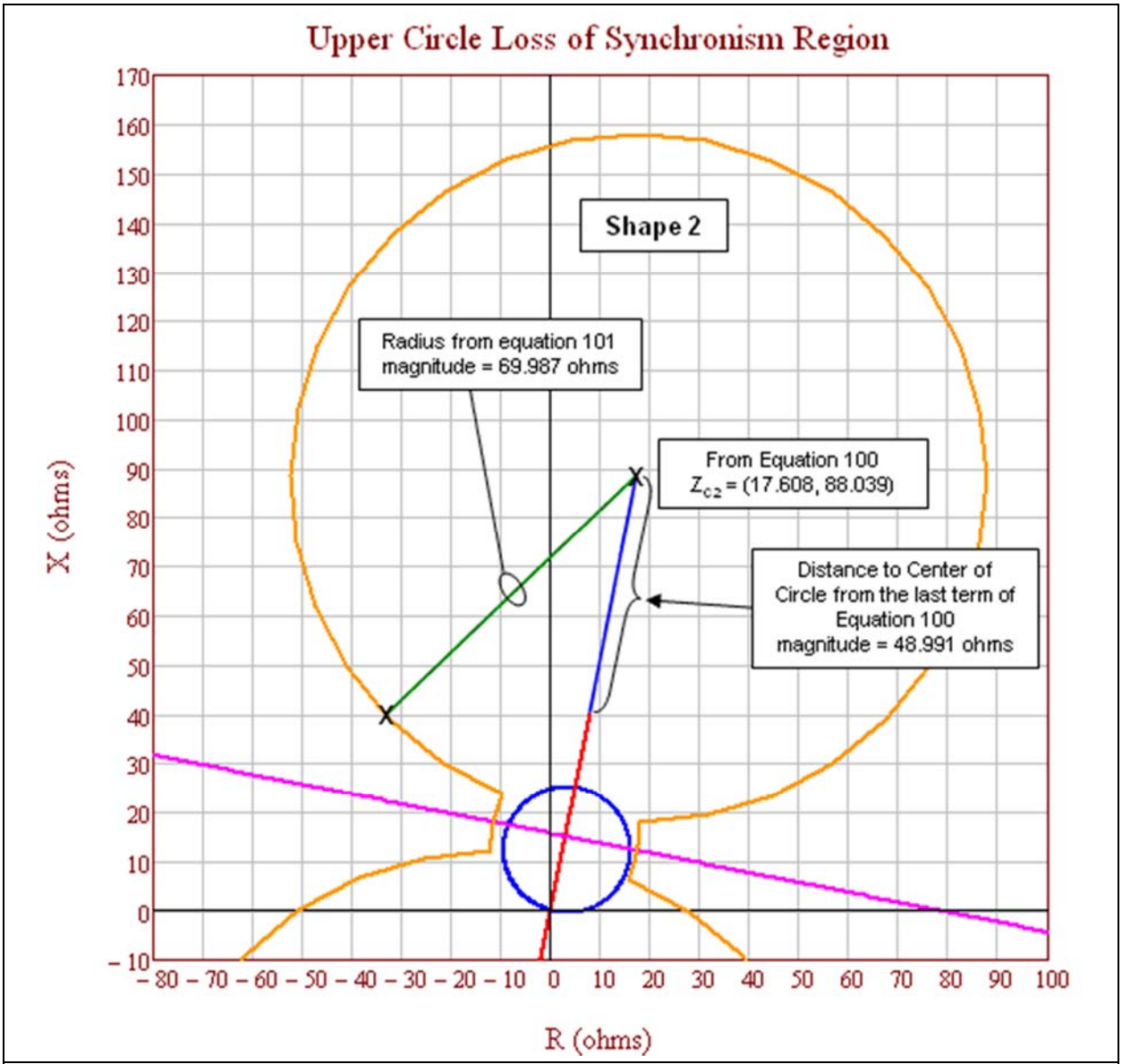

Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

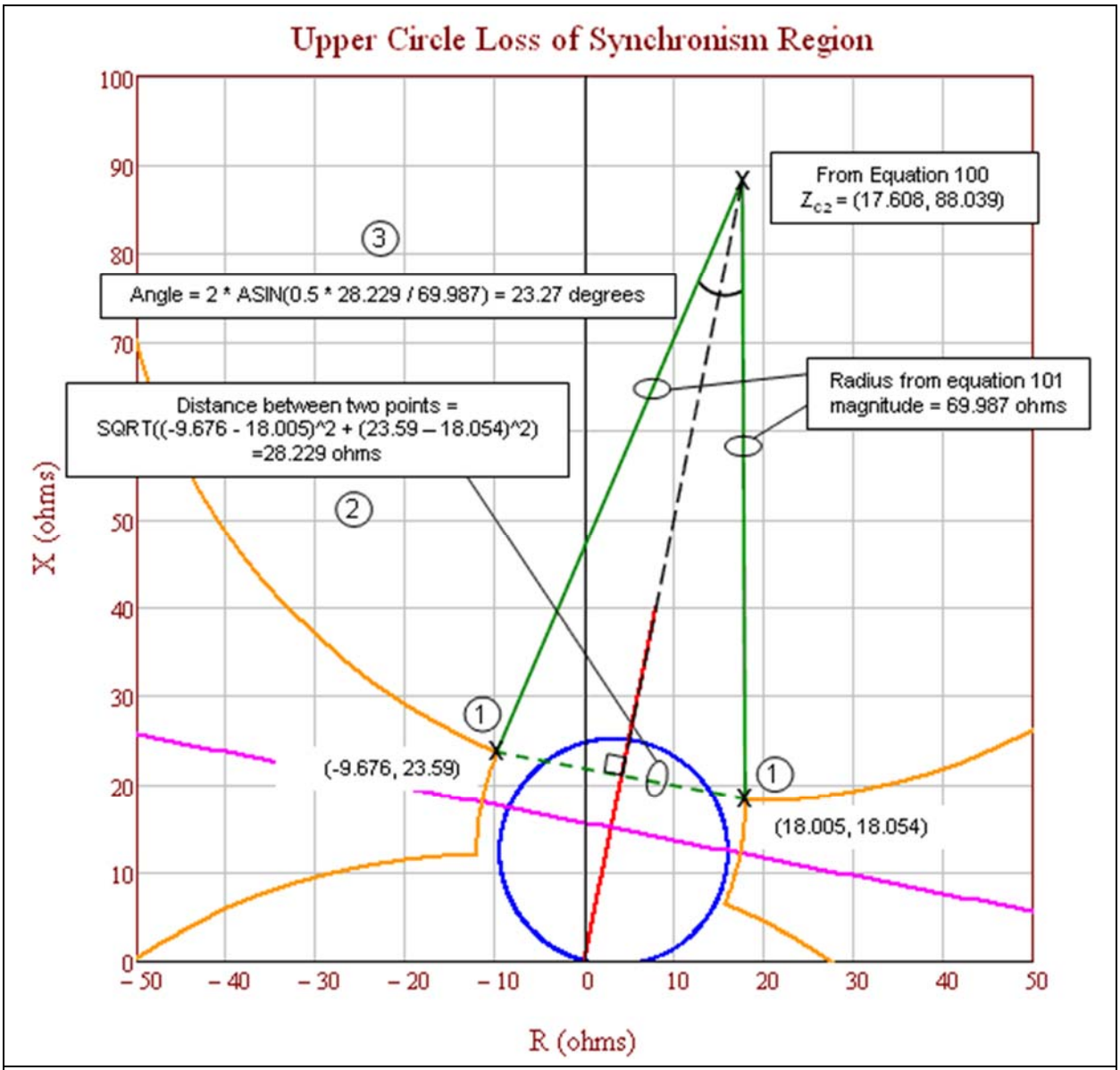

Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

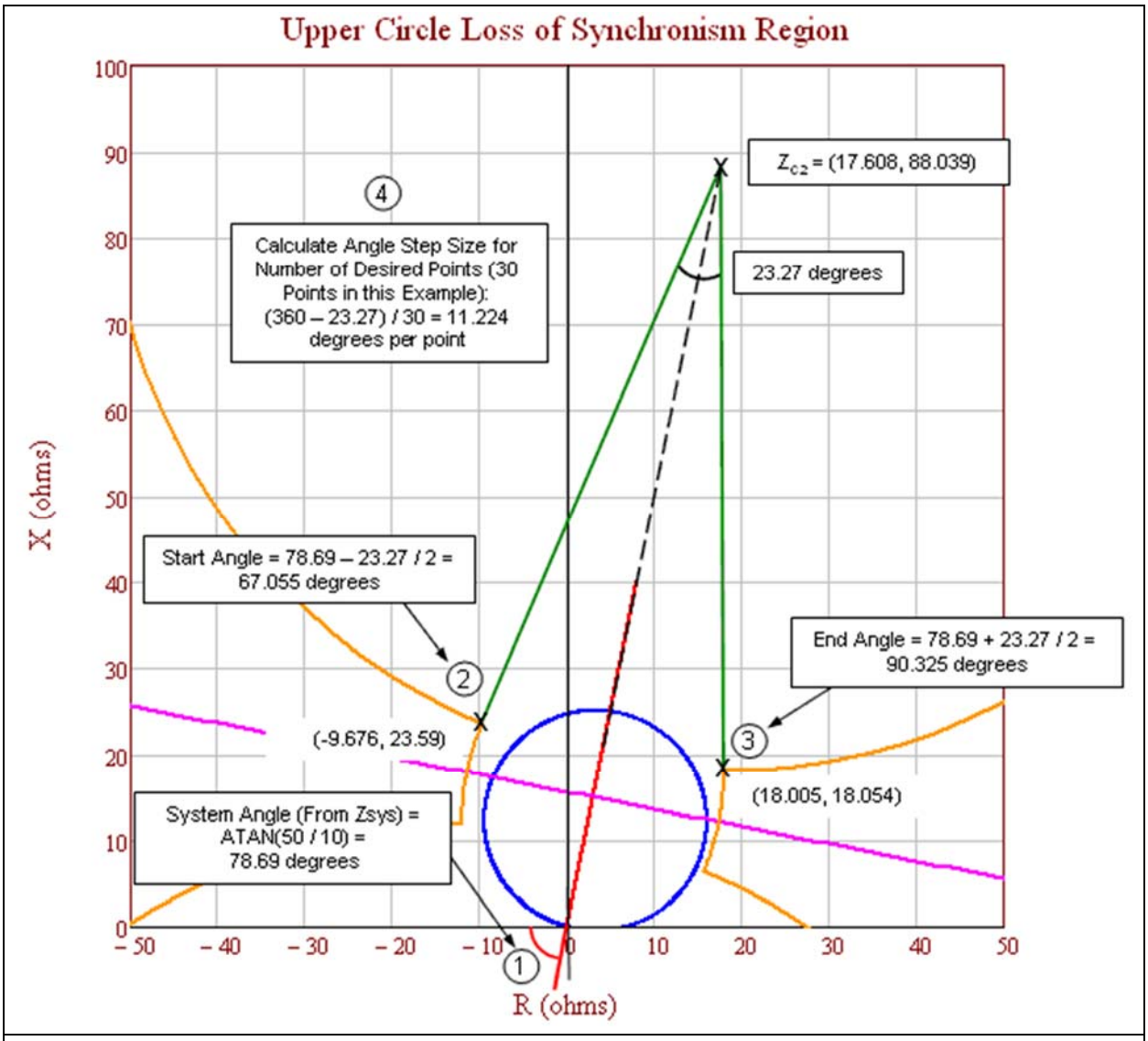

Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

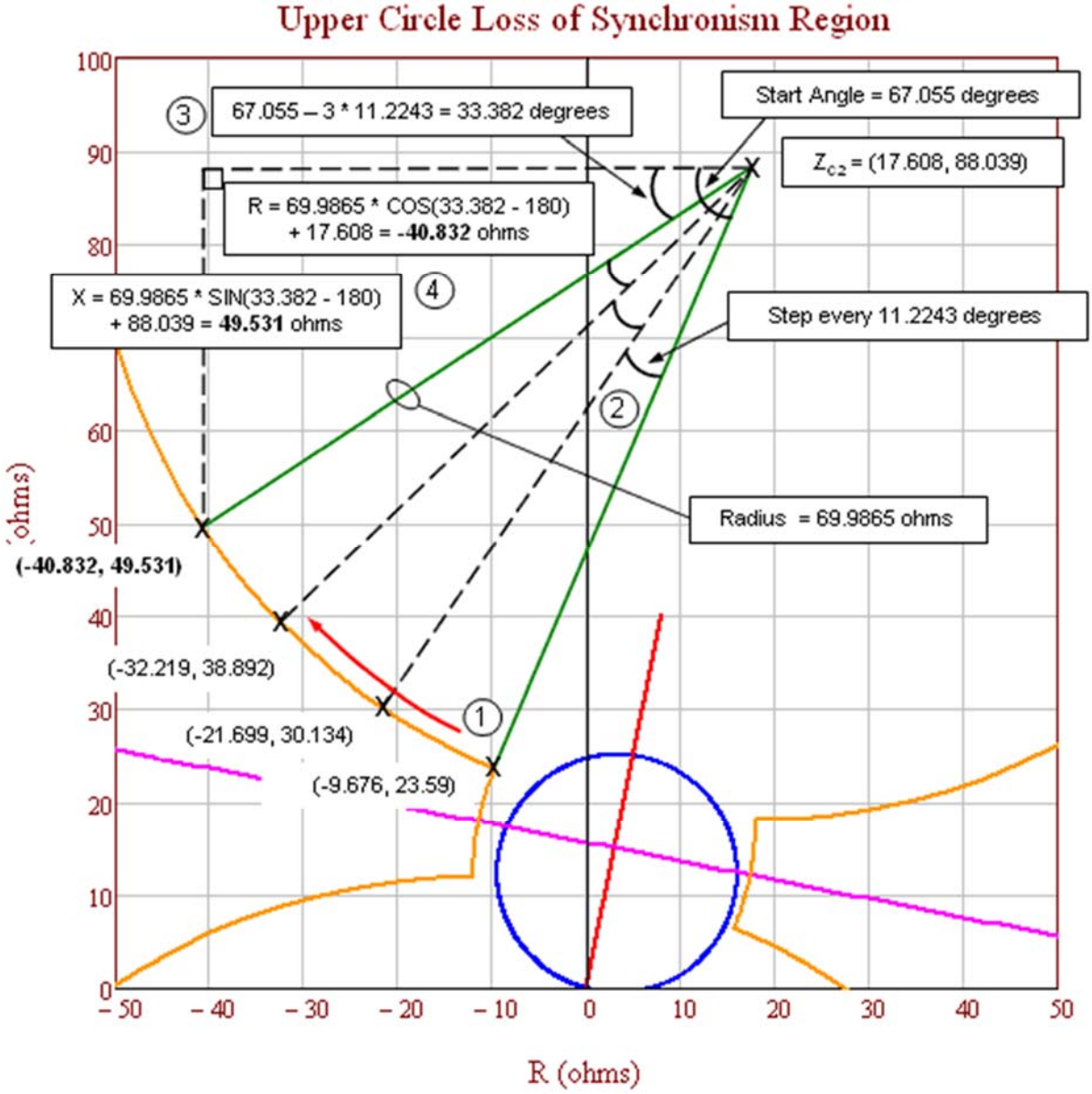

Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)

This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms.

Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.

Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

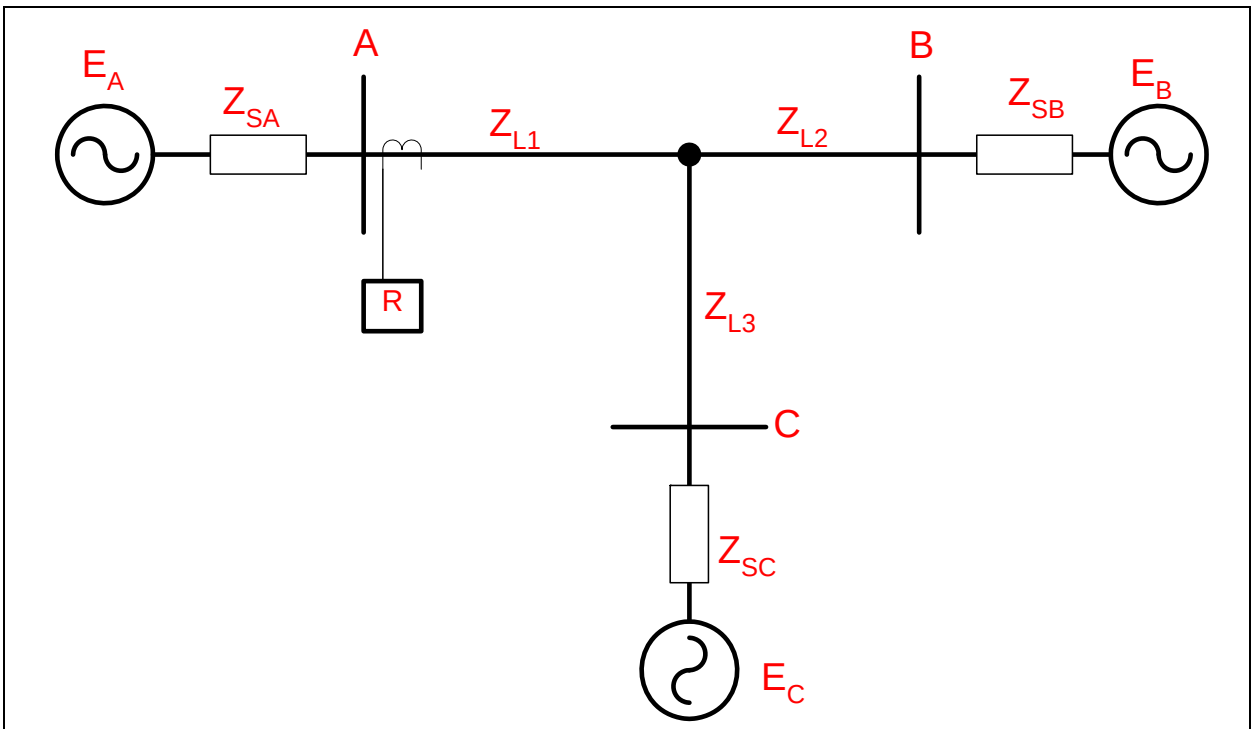

Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

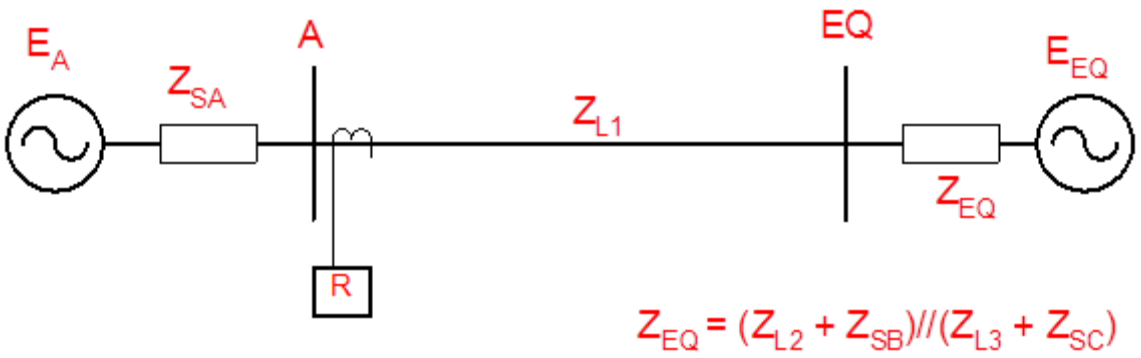

Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

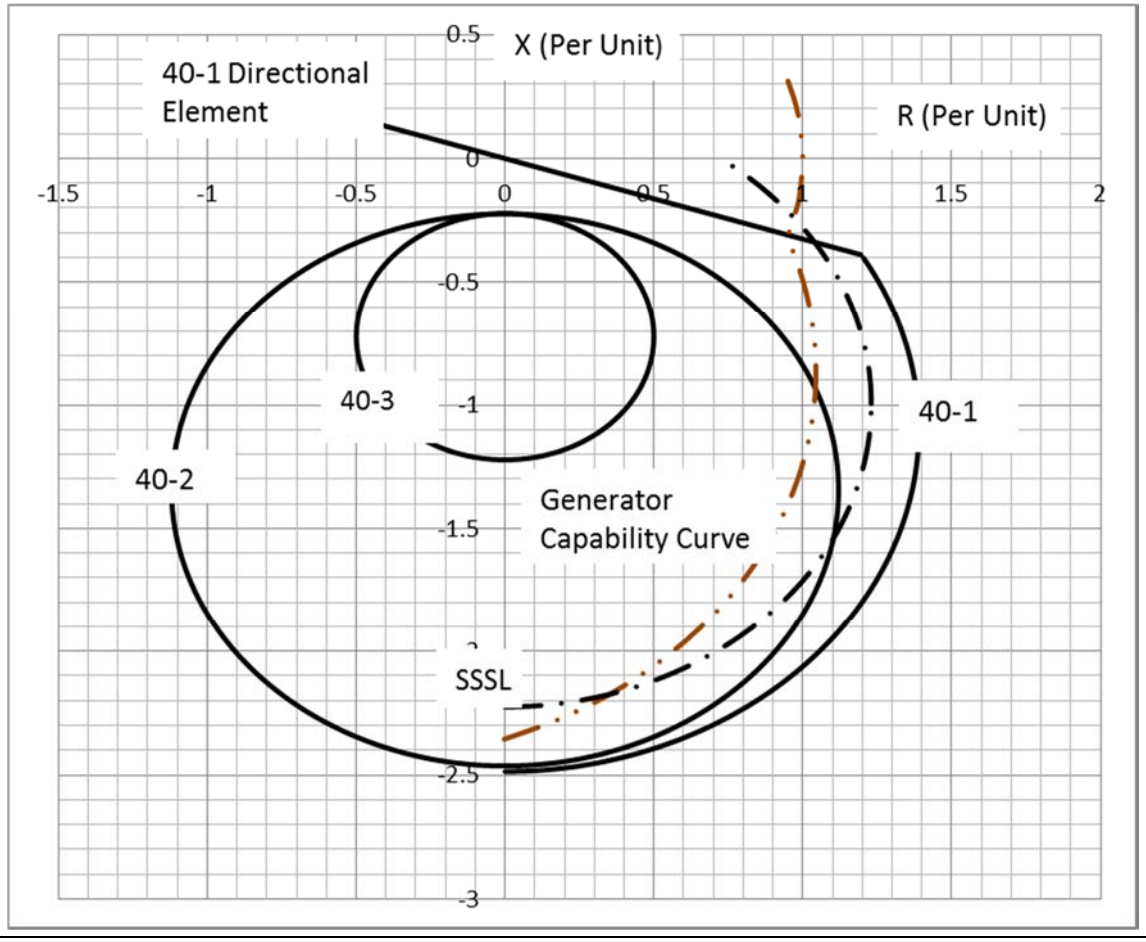

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

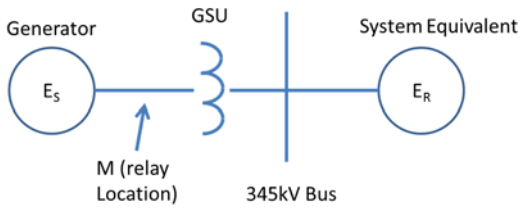

Figure 17: Simple one-line diagram of the system to be evaluated.

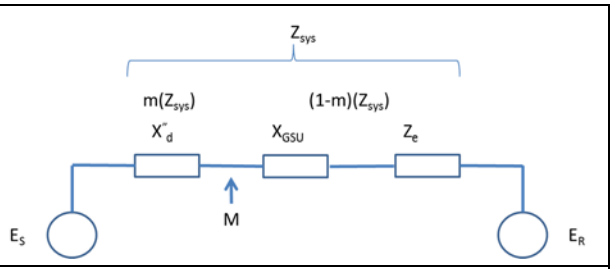

Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116 \angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194 \angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

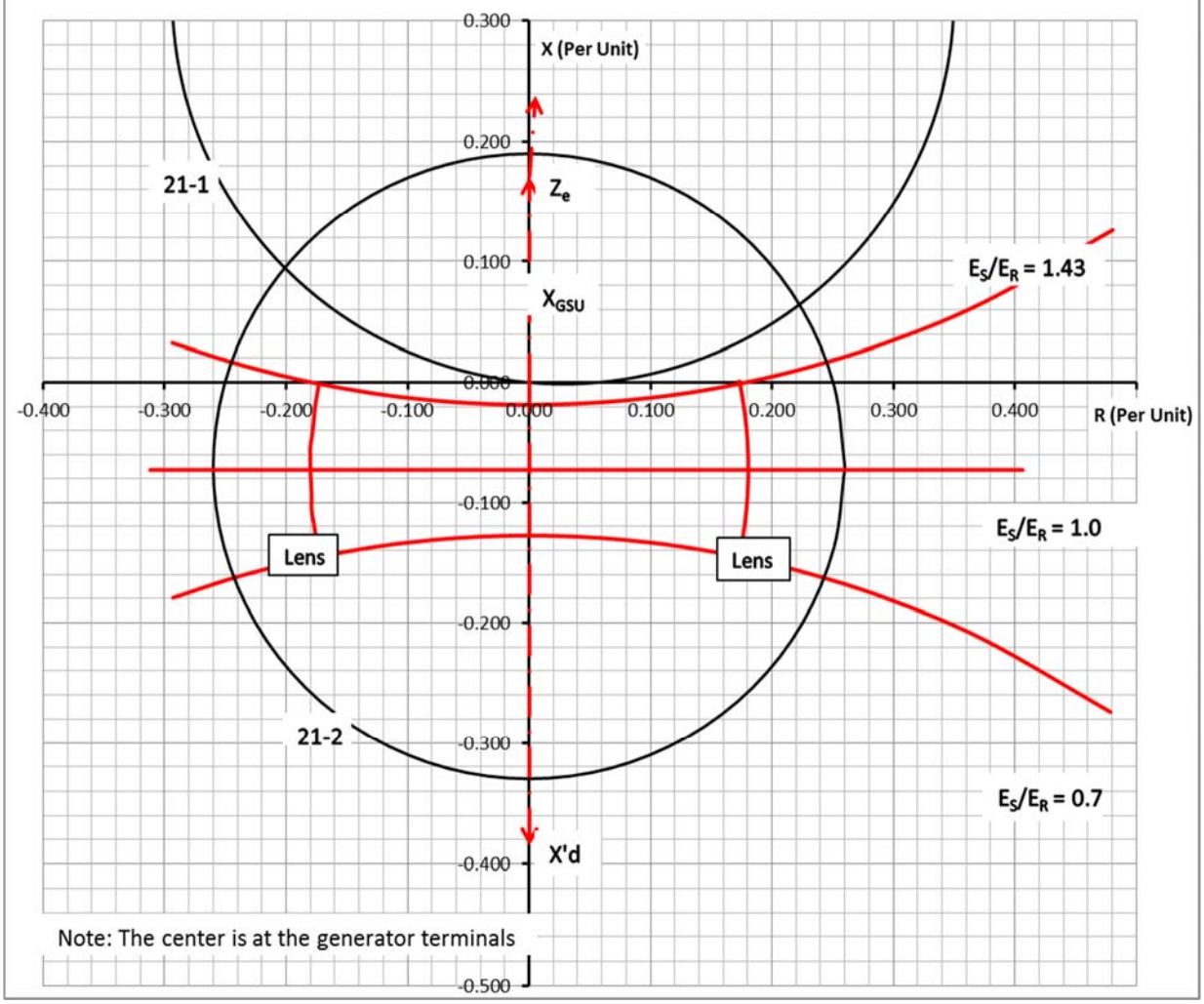

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

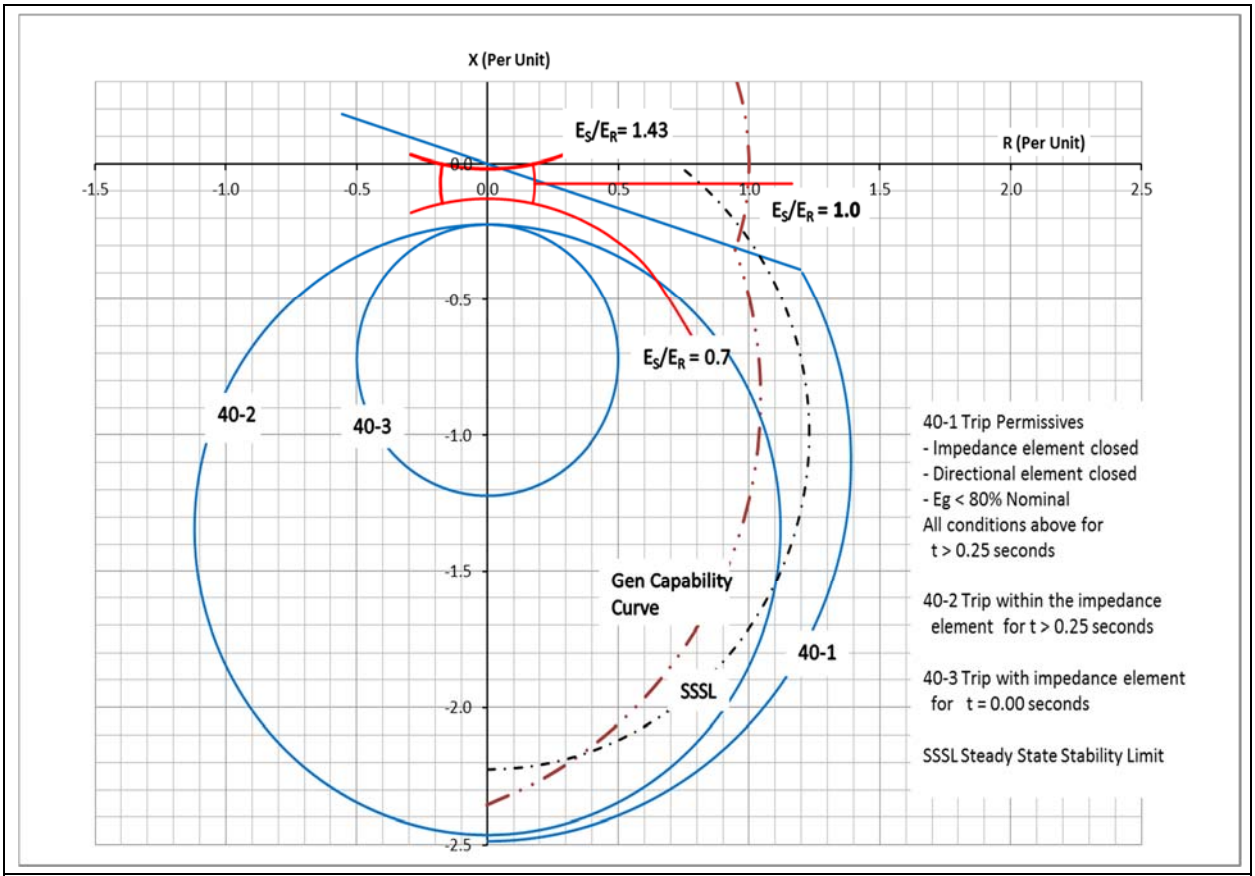

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

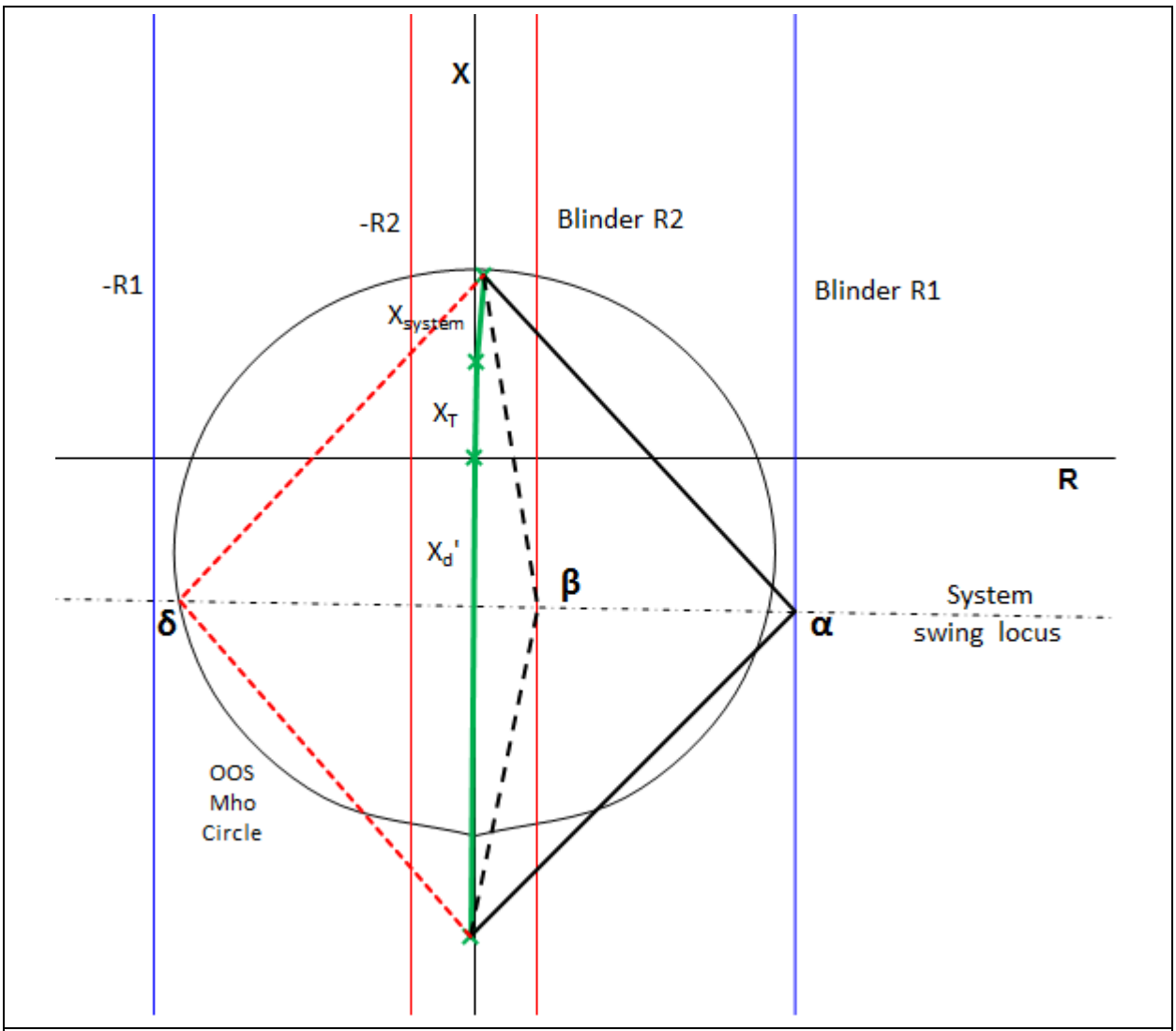

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

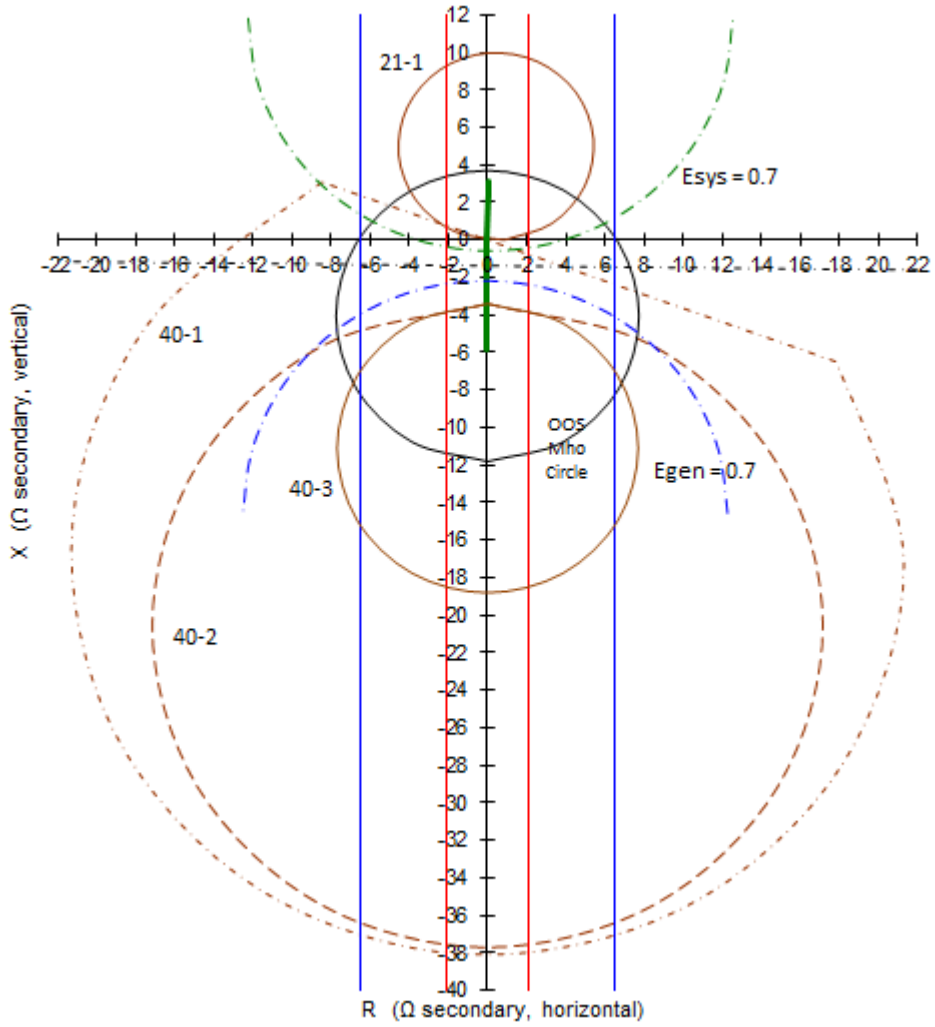

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

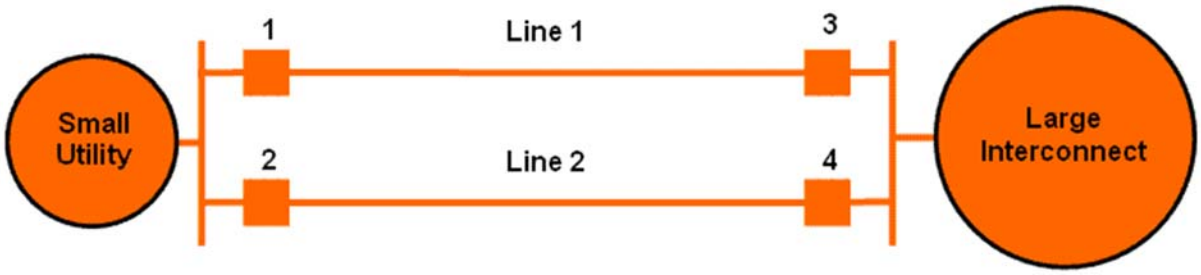

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

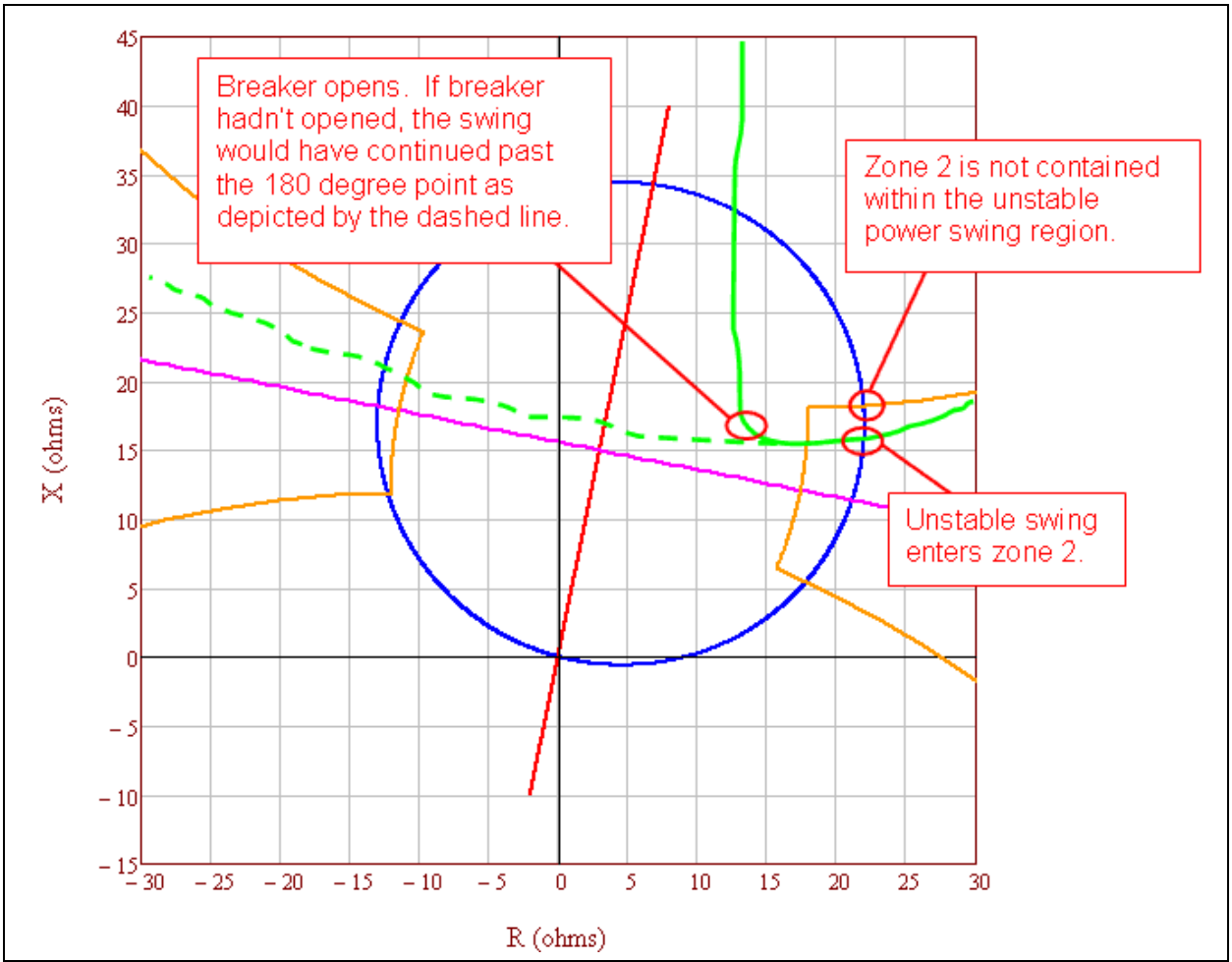

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

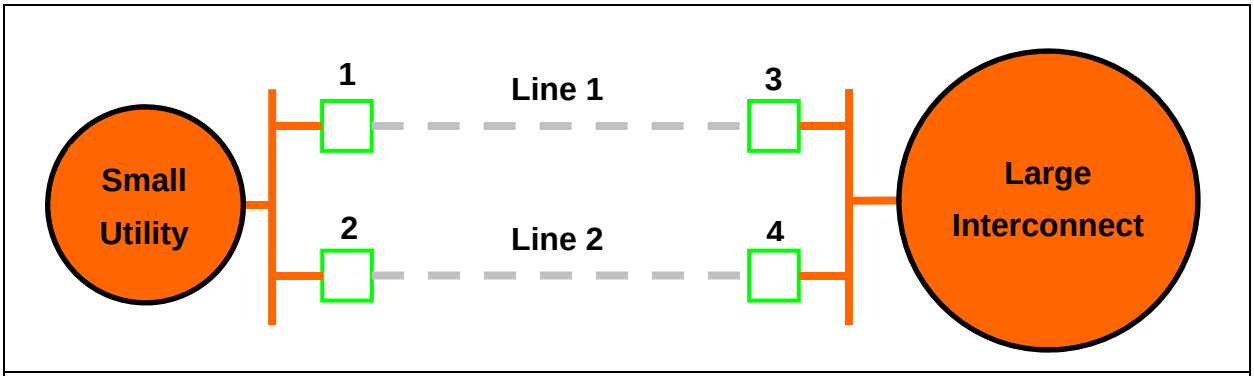

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

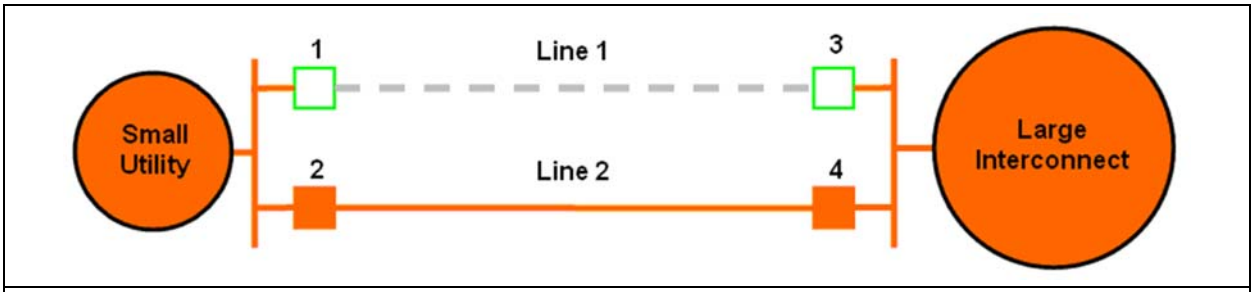

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

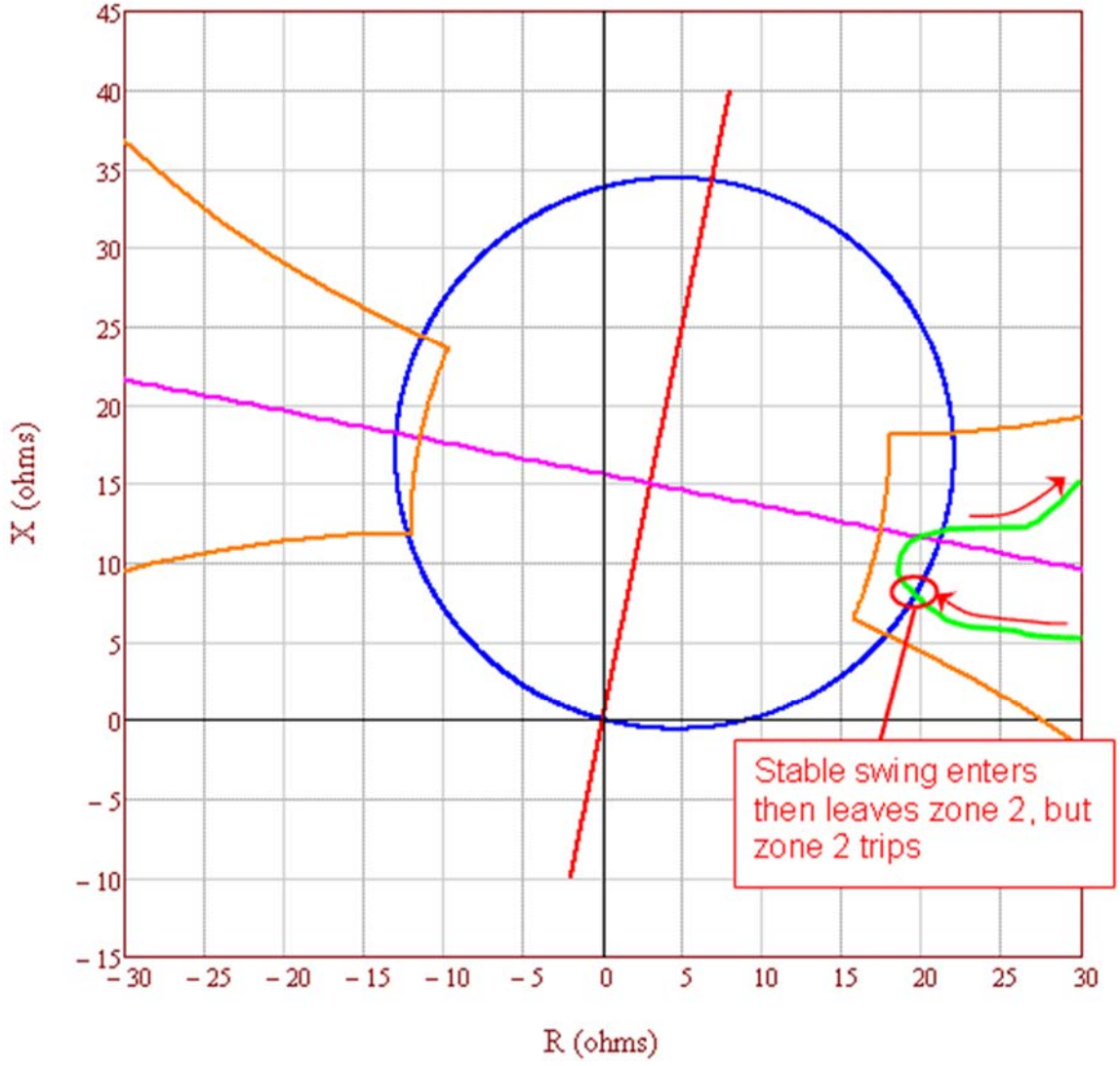

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

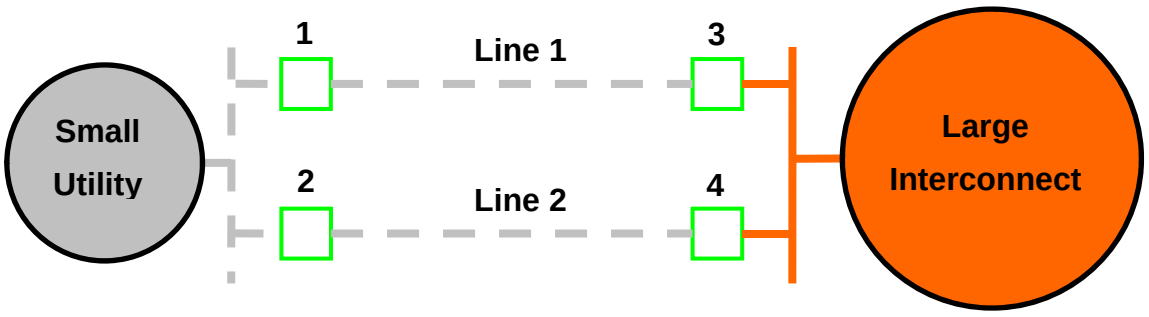

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL ") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3)
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2)
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3)
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2)

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts.

Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.
These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place

today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]
6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – 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.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – 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.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the standard drafting team posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT

abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and

stability criteria used in planning with those used in operations. The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.

As discussed in detail below, the SDT determined that references to "most limiting criteria" and "acceptable reliability criteria", and the manner in which the "specified system configuration" and the "pre- and post-contingency" phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria." Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this

concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

Acceptable Reliability Criteria – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

Specified System Configuration – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

Pre- and Post-Contingency – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

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 draft of the proposed standard.~~This will be the first draft adding the IROL removal language due to the retirement of the FAC-010 Reliability Standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
Standards Committee approved SAR for posting – IROL Modifications	August 22, 2018
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with initial ballot	August 22 – October 1, 2018

Anticipated Actions	Date
45-day formal comment period with additional ballot	~~May 18 – July 2, 2018~~November 11 – December 17, 2018
10-day final ballot	~~July 30 – August 8, 2018~~January 25 – February 5, 2018

NERC Board	~~August 16~~February 6, 2018

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-6

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

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

   4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

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

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

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

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

5. Effective Dates: ~~5.1~~ See implementation plan for CIP-002-6.

5.~~2~~1 Planned and Unplanned Changes: If a Responsible Entity has a Planned Change[1] or Unplanned Change,[2] the Responsible Entity shall comply with the requirements in this Reliability Standard as follows: ~~in accordance with the following:~~

For Planned Changes resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard upon the commissioned date of the Planned Change. For this provision, the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES. For requirements that contain periodic obligations, initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.

For Unplanned Changes~~,~~ resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below. As used in the table, the phrase "BES

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[1] Planned Changes ~~refer to~~ are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity's advance knowledge~~awareness~~. Planned Changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen~~that was foreseen~~ by the Responsible Entity. Examples of Planned Changes include, but are not limited to: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

[2] Unplanned Changes refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity's advance knowledge ~~awareness~~ or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of Unplanned Changes include, but are not limited to: (1) ~~when~~ a Responsible Entity is notified (internally or externally) that a generation Facility has been designated ~~as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year~~ per ~~(~~CIP-002, Attachment 1, Criterion 2.3~~)~~; (2) ~~when~~ a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per ~~as critical to the derivation of an IROL and their associated contingencies (~~CIP-002, Attachment 1, Criterion 2.6~~)~~; (3) ~~when~~ a generating resource that is connected at less than 100kV is designated ~~as a new Blackstart Resource along with its Cranking Path~~per ~~(~~ CIP-002, Attachment 1, Criterion 3.4~~)~~; or (4) ~~when~~ a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in CIP-002, Attachment 1, Criterion ~~Criterion~~ 2.10 ~~of CIP-002, Attachment 1~~.

asset type" refers to the following BES asset types listed in Requirement R1 of CIP-002: (i) Control Centers or backup Control Centers; (ii) Transmission stations or substations; (iii) generation resources; (iv) systems and facilities critical to system restoration including Blackstart Resources and Cranking Paths and initial switching requirements; (v) Remedial Action Schemes ~~Special Protection Systems~~ that support the reliable operation of the Bulk Electric System; and (vi) the Distribution Provider Protection Systems specified in Applicability section 4.2.1.

Scenario of Unplanned Change	Implementation Period
New **high impact** BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New **high impact** BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New **medium impact** BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New **medium impact** BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New **low impact** BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New **low impact** BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above, with the following exception: ~~except that~~ the Responsible Entity shall initially perform Part 2.2 of Requirement R2 by the date the Implementation Period ends where the Unplanned Change results in a high or medium impact BES Cyber System and the Responsible Entity previously had neither a high nor a medium impact BES Cyber System.

For Unplanned Changes resulting in a higher categorization for an existing BES Cyber System, the Responsible Entity shall continue to comply with the applicable requirements of the prior categorization during the Implementation Period defined in the table above.

6. **Background:** This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

   Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."

   BES Cyber Systems The term "BES Cyber System" is to provides a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

   It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

   Reliable Operation of the BES
   The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

   Real-time Operations

One characteristic of the BES Cyber Asset is ~~a~~ real-time scoping~~ characteristic.~~ The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the ~~application of these~~ CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," the following definition applies: BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not consider~~include in its consideration~~ the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria
The criteria provided~~defined~~ in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.13 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems
BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems ("PACS")** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. **Compliance Monitoring Process:**

   1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

   1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

   The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. Compliance Monitoring and Assessment Processes:

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

   1.4. Additional Compliance Information:
   None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Operations Planning**	**High**	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly	Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	**Operations Planning**	**Lower**	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location ~~that are~~ identified by the~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessments~~s~~ of the Near-Term Transmission Planning Horizon or ~~the Planning Coordinator's~~ its ~~-~~Transfer Capability a~~A~~ssessment (Planning Coordinator only), as Facilities~~,~~ that~~,~~ if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent ~~or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would~~ 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~~.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry's overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document[3] to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center's associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center's associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

[3] This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

2.12. Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. Remedial Action Schemes that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.
These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO, GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO,TOP, GO, GOP)
- Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (~~real-~~real-time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in ~~real-~~real-time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions, and conditions which ensure, in ~~real-~~real-time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO, DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP, TO, DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO, DP)

Managing Constraints

Managing Constraints includes activities, actions, and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor System Operating Limits ~~'s~~(SOLs) & Interconnection Reliability Operating Limit (IROL)~~'s~~ (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions, and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions, and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situational Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC, BA)
- Change management (TOP, GOP, RC, BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)

- Frequency monitoring (BA, RC)

Inter-Entity Coordination and Communication

The Inter-Entity ~~coordination~~ Coordination and ~~communication~~ Communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these ~~Version 5 Cyber Security~~CIP Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.13 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For

example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports ~~Distribution~~ distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3, and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, ~~Bas~~BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002-1, whose purpose ~~is~~ was "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires~~d~~ that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BA~~a~~s in all regions.

  In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

  By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

  The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified

as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified in a Planning Assessments of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

  Instances of instability, Cascading, or uncontrolled separation IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Identification of these instances Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes designates those BES Cyber Systems for in Remedial Action Schemes (RAS) may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact. installed to ensure reliable BES operation as medium impact. The degradation, misuse, or unavailability of these BES Cyber Systems could potentially result in Wide Area

impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in instability, Cascading, or uncontrolled separation~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~. Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

  It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500 kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

  The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

  Additionally, in NERC's document "~~Integrated Risk Assessment Approach – Refinement to Severity Risk Index~~Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:
  - 230 kV –> 700 MVA
  - 345 kV –> 1,300 MVA
  - 500 kV –> 2,000 MVA
  - 765 kV –> 3,000 MVA

  In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:
  - For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
  - Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

  Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

  1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
  2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

  The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 includes BES Cyber Systems for those Transmission Facilities that have been identified in a Planning Assessment of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation

owner as to the qualification of generation Facilities connected to their Transmission systems.

- Criterion 2.9 designates ~~as medium impact~~ those BES Cyber Systems~~, for those~~ in Remedial Action Schemes (RAS)~~ or automated switching Systems,~~ installed to ensure reliable BES operation as medium impact~~within IROLs~~. The degradation, ~~compromise~~misuse, or unavailability of these BES Cyber Systems could potentially ~~would~~ result in ~~exceeding IROLs~~ Wide Area impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed. ~~By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~
- Criterion 2.10 designates ~~as medium impact~~ those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more as medium impact. The SDT ~~spent considerable time~~ discussed~~ing~~ the wording of Criterion 2.10, and chose the term "Each" to show~~represent~~ that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team ~~sought to~~ included only those Systems that did not require human operator initiation, and targeted ~~in particular~~ those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. T~~It should be noted that t~~hose qualifying systems which require a human operator to arm the system and subsequently~~, but once armed,~~ trigger automatically, are still ~~to be~~ considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards~~,~~ for the preceding 12 months to account for seasonal fluctuations.

  The ~~is particular threshold (~~300 MW~~)~~ threshold was provided in ~~CIP,~~ Version 1 of the CIP Reliability Standards. The SDT believes that the threshold should be lower than the 1500 MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and ~~and hence~~ requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

  In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs ~~that~~ are not part of the NERC or regional reliability Load shedding programs. They ~~, but~~ are offered as components of an ancillary services market and do not qualify under this criterion.

  The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that define ~~would ensure~~ the required level of impact to the BES ~~is defined~~ and an associated ~~a~~ risk threshold ~~associated~~ to establish a floor for applicable medium impact BES Cyber Systems.

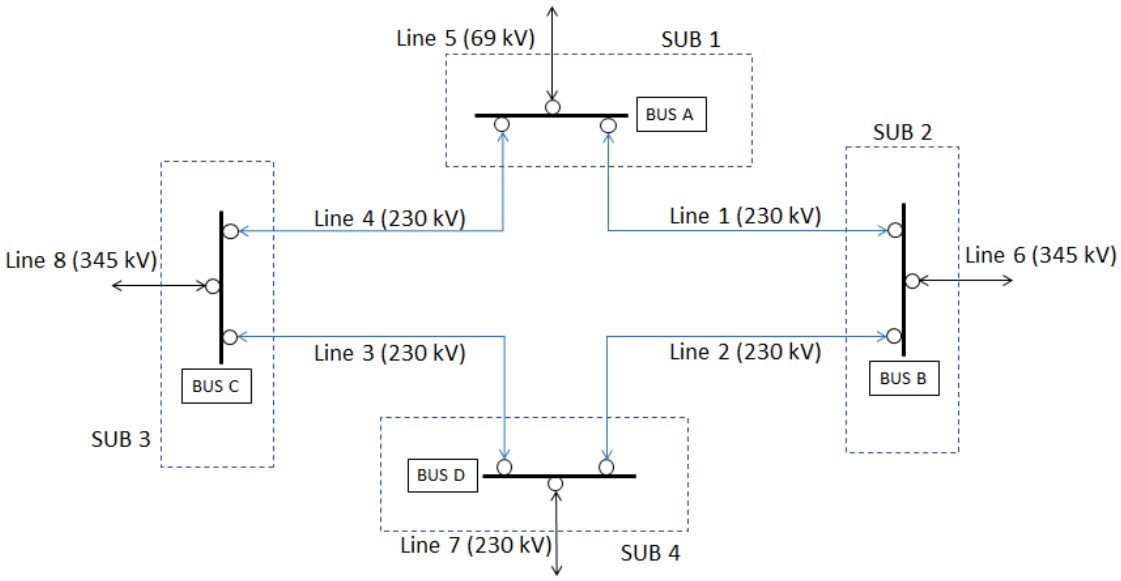
  The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at ~~an a~~~~ppropriate~~ level commensurate with the associated risk.

  In the terms of applicable BES Transmission Lines, the following should be considered:

  - All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
  - All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
  - Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
  - Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

  Criterion 2.12 Examples:

  In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

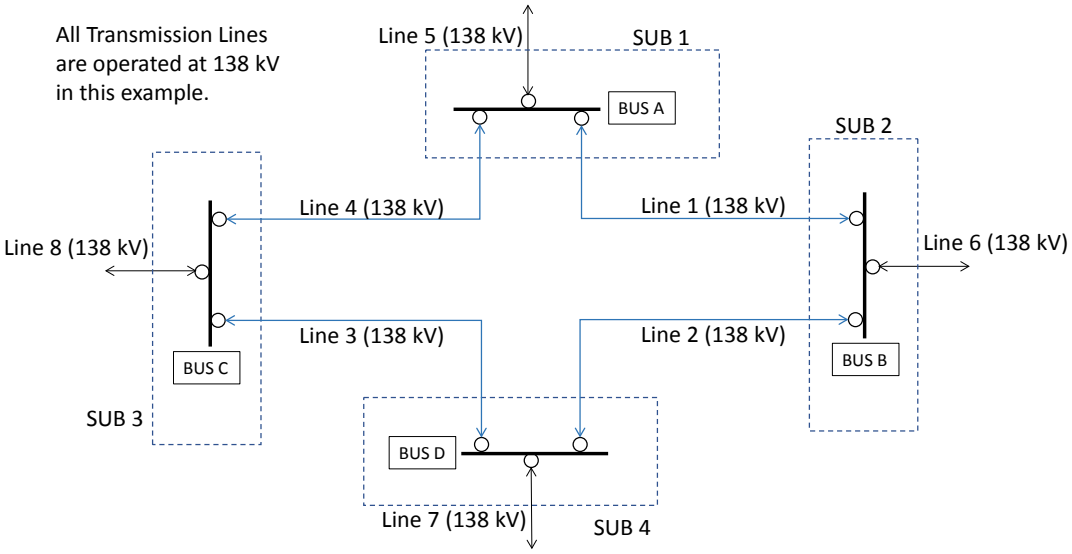
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

700+700+700+700+700+1300+1300 = 6100

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A

100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

  In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

  The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration

assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005~~-2~~ requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005~~-2~~ to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

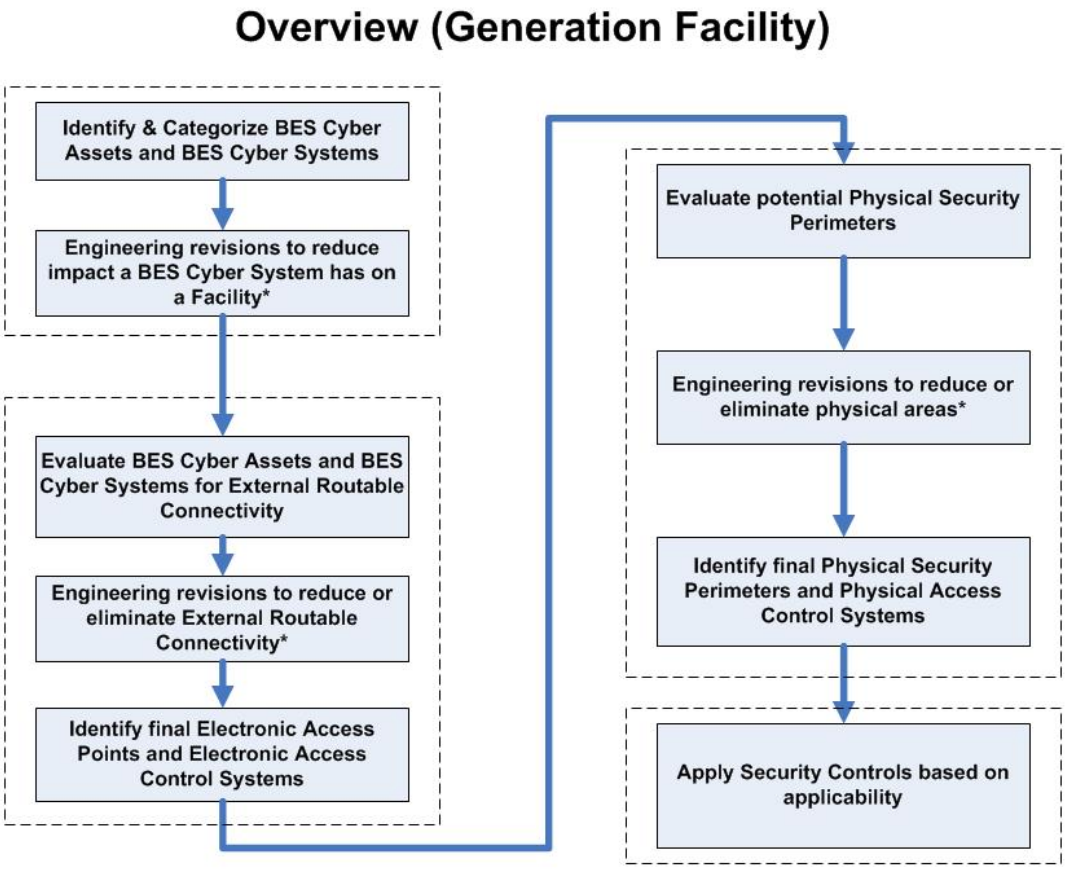
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005~~-2~~, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

  Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a ~~generator~~ Generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber

Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:
BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:
The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

> Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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-002-6**. 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-002-6, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity's CIP management program.
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 VRF is not being modified for this requirement. The modification is a clarification of Criteria~~on~~ 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity's CIP management program. The modification is a clarification of Criteria~~on~~ 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems

have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber	medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber	have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	

VSL Justifications for CIP-002-6 Requirements R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criteria~~on~~ 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.
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 VSL has not been modified for this requirement since there is no change to Requirement R1. 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 VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is ~~three~~ fifteen (~~3~~15) 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-002-6 shall become effective on the first day of the first calendar quarter that is ~~three~~ fifteen (~~3~~15) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

~~For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber Security Standards.~~

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

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

45-day initial formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 13, 2018
SAR posted for comment	June 13 – July 13, 2018

Anticipated Actions	Date
45-day formal comment period with ballot (initial)	August 23 – October 8, 2018
10-day final ballot	October 29 – November 8, 2018
Board adoption	February 2019

A. Introduction

1. Title: Cyber Security — Security Management Controls

2. Number: CIP-003-8~~7~~

3. Purpose: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. Applicability:

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

4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~4.1.6.~~4.1.5. Reliability Coordinator

~~4.1.7.~~4.1.6. Transmission Operator

~~4.1.8.~~4.1.7. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-003-~~8~~7:

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

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

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

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

5. Effective Dates:

See Implementation Plan for CIP-003-~~7~~8.

5.1. Planned and Unplanned Changes: For any Planned Change or Unplanned Change, as those terms are defined in the Effective Dates Section of Reliability Standard CIP-002, the Responsible Entity must comply with the requirements in this Reliability Standard on the date the Responsible Entity must comply with the requirements in Reliability Standard CIP-002 following a Planned Change or Unplanned Change.

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2. For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls;

1.2.4. Cyber Security Incident response;

1.2.5. Transient Cyber Assets and Removable Media malicious code risk mitigation; and

1.2.6. Declaring and responding to CIP Exceptional Circumstances.

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information:
None.

Violation Severity Levels~~Table of Compliance Elements~~

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR The Responsible Entity did not

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1)	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1)	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar	BES Cyber Systems, but did not address three of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address four or more of the six topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR The Responsible Entity did not

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.2)	calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for electronic access controls according to Requirement R2,	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic	The Responsible Entity failed to document and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing	to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but	access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented	failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2,	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			its plan(s) for Transient Cyber Assets, but failed to document the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2)	according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2,	Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber	the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2,		

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 5.3. (R2)		
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	**Operations Planning**	**Lower**	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~8~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	

Version	Date	Action	Change Tracking
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	2/9/17	Adopted by the NERC Board of Trustees.	Revised to address FERC Order No. 822 directives regarding (1) the definition of LERC and (2) transient devices.
7	4/19/18	FERC Order issued approving CIP-003-7. Docket No. RM17-11-000	

Version	Date	Action	Change Tracking
8		FERC Order issued approving CIP-003-7. Docket No. RM17-11-000	

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: For each asset containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement electronic access controls to:

3.1 Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:

i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);

ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and

iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).

3.2 Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the

Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation: Each Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more plan(s) to achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media. The plan(s) shall include:

5.1 For Transient Cyber Asset(s) managed by the Responsible Entity, if any, the use of one or a combination of the following in an ongoing or on-demand manner (per Transient Cyber Asset capability):

- Antivirus software, including manual or managed updates of signatures or patterns;
- Application whitelisting; or
- Other method(s) to mitigate the introduction of malicious code.

5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any:~~,~~

~~**5.1.1**~~**5.2.1** ~~the u~~Use ~~of~~ one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;
- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;
- Review of system hardening used by the party; or

- Other method(s) to mitigate the introduction of malicious code.

~~5.1.2~~5.2.2 For any method used pursuant to 5.2.1, Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset.

~~5.2~~5.3 For Removable Media, the use of each of the following:

~~5.2.1~~5.3.1 Method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System; and

~~5.2.2~~5.3.2 Mitigation of the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System.

Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset(s) specified by the Responsible Entity that provide(s) electronic access controls implemented for Attachment 1, Section 3.1, if any.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation showing that at each asset or group of assets containing low impact BES Cyber Systems, routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset is restricted by electronic access controls to permit only inbound and outbound electronic access that the Responsible Entity deems necessary, except where an entity provides rationale that communication is used for time-sensitive protection or control functions between intelligent electronic devices. Examples of such documentation may include, but are not limited to representative diagrams that illustrate control of inbound and outbound communication(s) between the low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) or lists of implemented electronic access controls (e.g., access control lists restricting IP addresses, ports, or services; implementing unidirectional gateways).

2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity Information Sharing and Analysis Center (E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation:

1. Examples of evidence for Section 5.1 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

2. Examples of evidence for Section 5.2.1 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that

identifies the Responsible Entity's acceptance that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate malicious code for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Examples of evidence for Attachment 1, Section 5.2.2 may include, but are not limited to, documentation from change management systems, electronic mail, or contracts that identifies a review to determine whether additional mitigation is necessary and has been implemented prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity.

~~2.~~3. Examples of evidence for Section 5.3.1 may include, but are not limited to, documented process(es) of the method(s) used to detect malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Examples of evidence for Section 5.3.2 may include, but are not limited to, documented process(es) for the method(s) used for mitigating the threat of detected malicious code on Removable Media, such as logs from the method(s) used to detect malicious code that show the results of scanning and the mitigation of detected malicious code on Removable Media or documented confirmation by the entity that the Removable Media was deemed to be free of malicious code.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-8~~7~~, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-8~~7~~, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the six subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-~~7~~8, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy

appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

1.1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components
- Availability of system backups

1.1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

For Part 1.2, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for assets containing low impact BES Cyber Systems, if any:

1.2.1 Cyber security awareness

- Method(s) for delivery of security awareness
- Identification of groups to receive cyber security awareness

1.2.2 Physical security controls

- Acceptable approach(es) for selection of physical security control(s)

1.2.3 Electronic access controls

- Acceptable approach(es) for selection of electronic access control(s)

1.2.4 Cyber Security Incident response

- Recognition of Cyber Security Incidents

- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.2.5 Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

- Acceptable use of Transient Cyber Asset(s) and Removable Media
- Method(s) to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media
- Method(s) to request Transient Cyber Asset and Removable Media

1.2.6 Declaring and responding to CIP Exceptional Circumstances

- Process(es) to declare a CIP Exceptional Circumstance
- Process(es) to respond to a declared CIP Exceptional Circumstance

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that address the security objective for the protection of low impact BES Cyber Systems. The required protections are designed to be part of a program that covers the low impact BES Cyber Systems collectively at an asset level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate "how" the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The standard drafting team does not intend for Responsible Entities to be required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or "If you see something, say something" campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Attachment 1, Section 3.1, if any. If these Cyber Assets implementing the electronic access controls are located within the same asset as the low impact BES Cyber Asset(s) and inherit the same physical access controls and the same need as outlined in Section 2, this may be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility to select the methods used to meet the objective of controlling physical access to (1) the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a

combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses.

The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level. The standard drafting team did not intend to obligate an entity to specify a need for each physical access or authorization of an individual for physical access.

Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The standard drafting team's intent is that the monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.

User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of electronic access controls for assets containing low impact BES Cyber Systems when there is routable protocol communication or Dial-up Connectivity between Cyber Asset(s) outside of the asset containing the low impact BES Cyber System(s) and the low impact BES Cyber System(s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity.

When implementing Attachment 1, Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and outbound electronic access are required for communications when those communications meet all three of the criteria identified in Attachment 1, Section 3.1. The Responsible Entity should evaluate the communications and when all three criteria are met, the Responsible Entity must document and implement electronic access control(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems that use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.

In essence, the intent is for Responsible Entities to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity to the low impact BES Cyber System(s). Where such

communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.

The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, it is not intended for communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), to be evaluated for electronic access controls.

Electronic Access Control Exclusion

In order to avoid future technology issues, the obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Considerations for Determining Routable Protocol Communications

To determine whether electronic access controls need to be implemented, the Responsible Entity has to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset.

When determining whether a routable protocol is entering or leaving the asset containing the low impact BES Cyber System(s), Responsible Entities have flexibility in identifying an approach. One approach is for Responsible Entities to identify an “electronic boundary” associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the routable protocol communication entering or leaving the asset between a low impact BES Cyber System and Cyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located

at the asset are contained within the "electronic boundary." This is strictly for determining which routable protocol communications and networks are internal or inside or local to the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an "electronic boundary," but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the intent is for the Responsible Entity to document and implement its chosen electronic access control(s). The control(s) are intended to allow only "necessary" inbound and outbound electronic access as determined by the Responsible Entity. However the Responsible Entity chooses to document the inbound and outbound access permissions and the need, the intent is that the Responsible Entity is able to explain the reasons for the electronic access permitted. The reasoning for "necessary" inbound and outbound electronic access controls may be documented within the Responsible Entity's cyber security plan(s), within a comment on an access control list, a database, spreadsheet or other policies or procedures associated with the electronic access controls.

Concept Diagrams

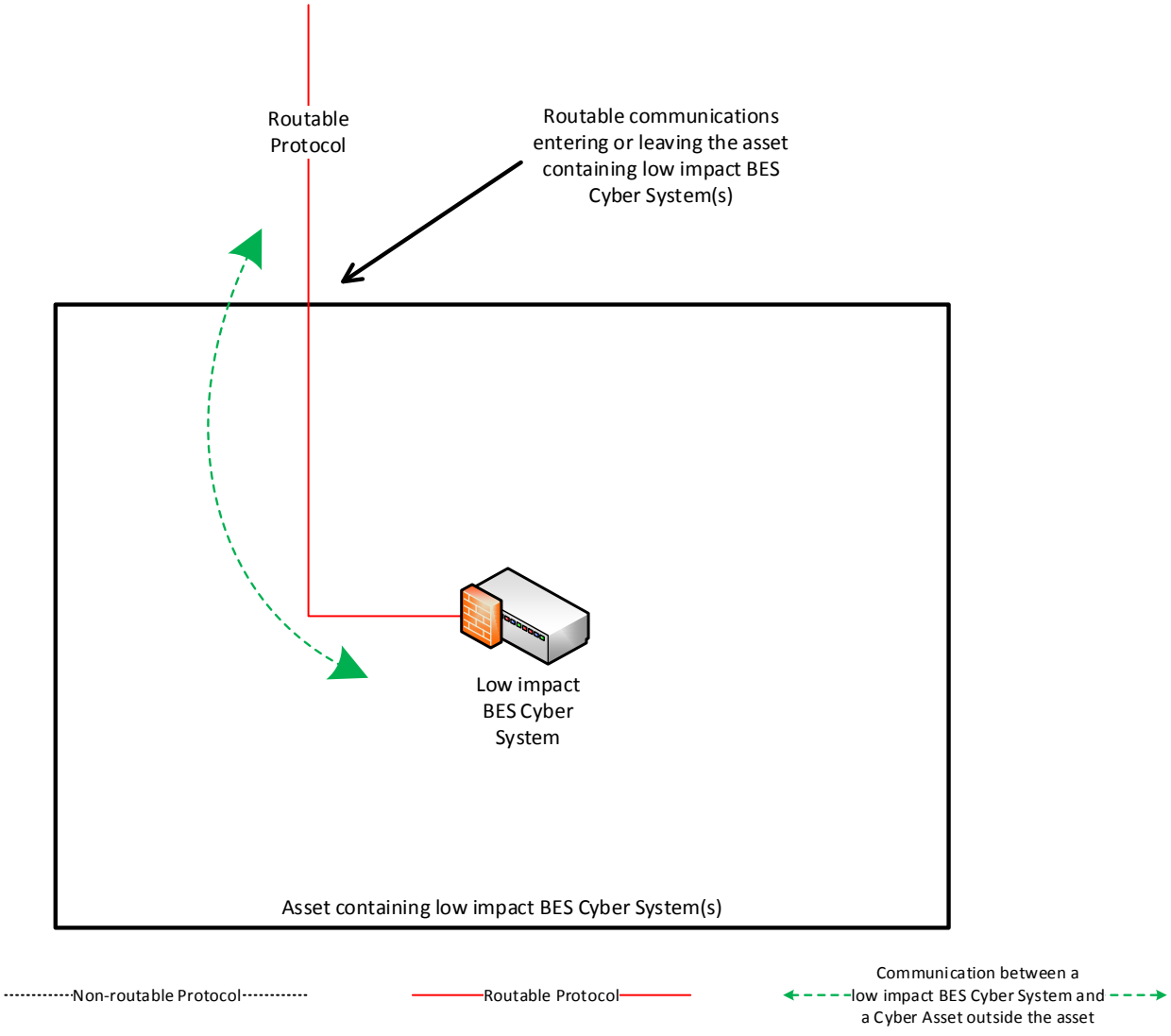
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the intent is to achieve the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

Reference Model 1 – Host-based Inbound & Outbound Access Permissions

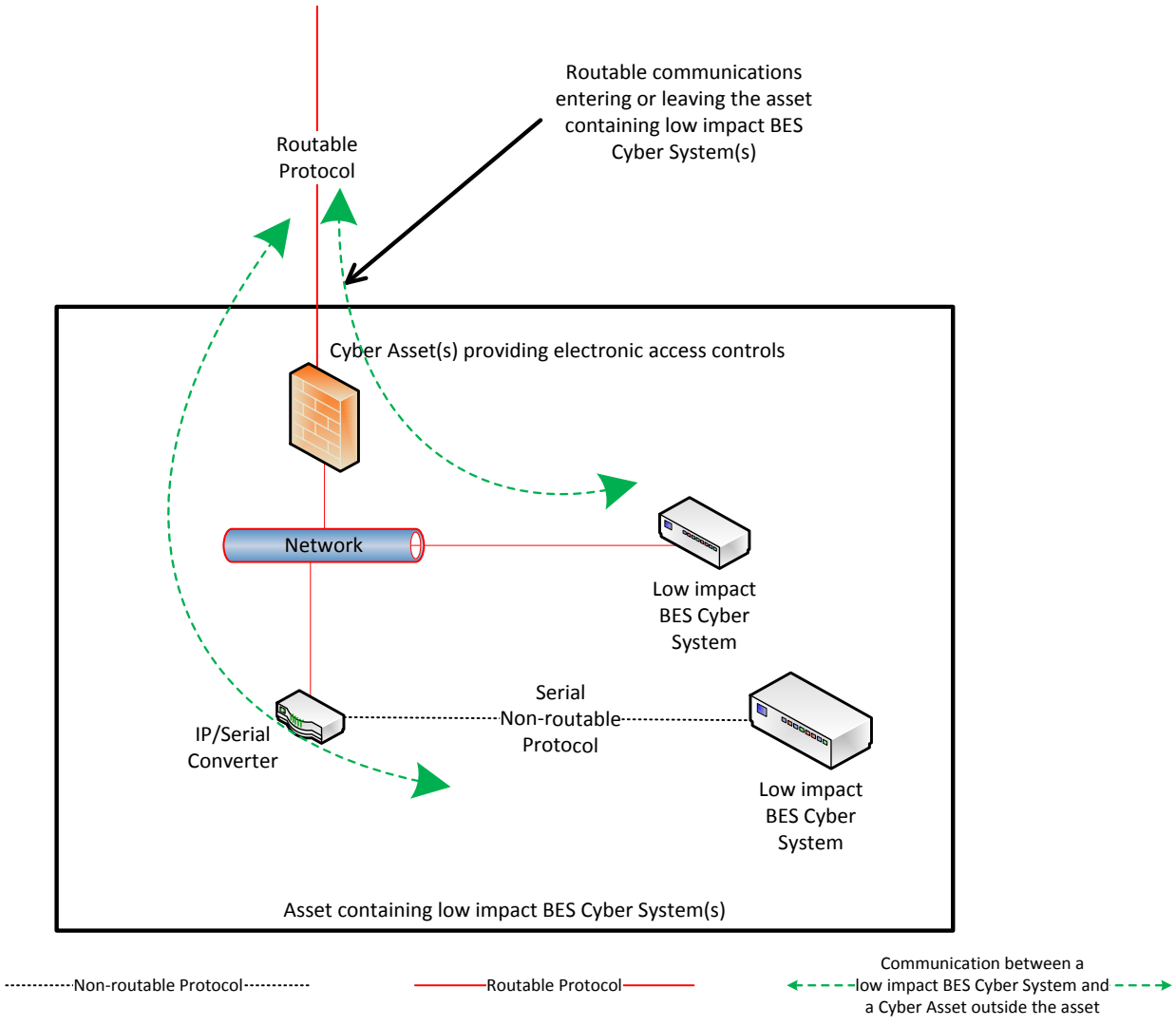
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound electronic access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 1

Reference Model 2 – Network-based Inbound & Outbound Access Permissions

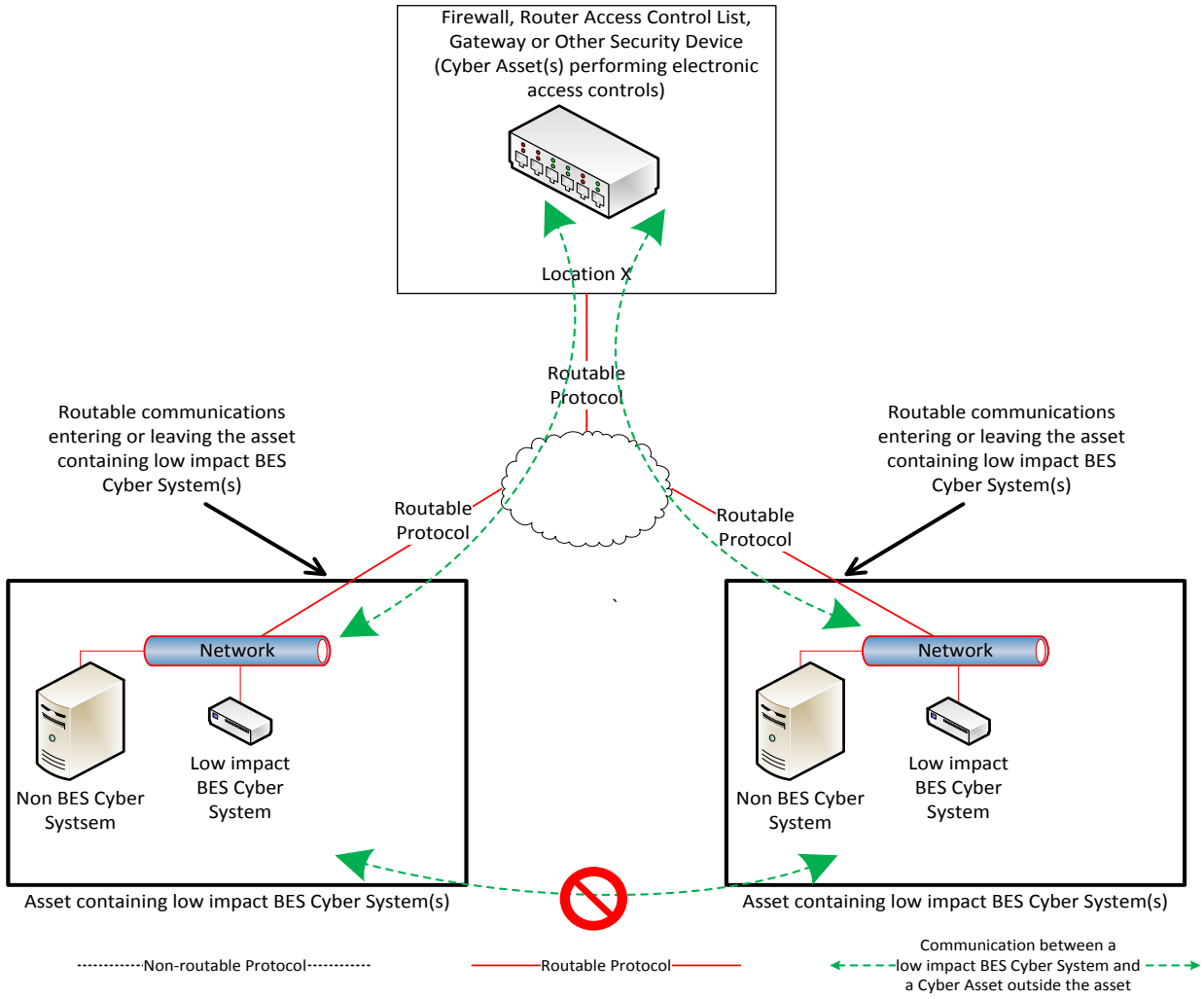
The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 2

Reference Model 3 – Centralized Network-based Inbound & Outbound Access Permissions

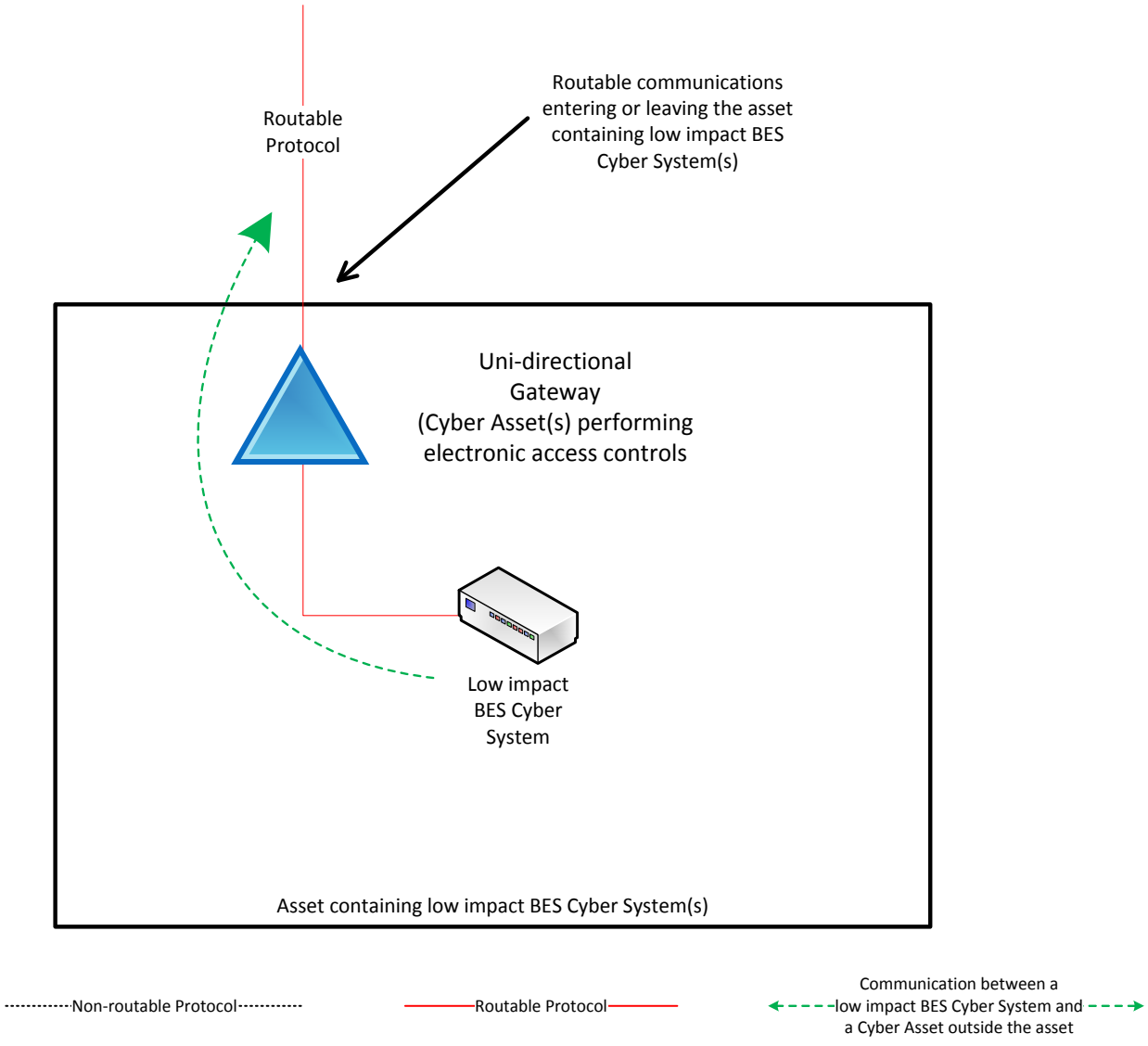
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be at another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the Cyber Asset(s) determined by the Responsible Entity to be performing electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3

Reference Model 4 – Uni-directional Gateway

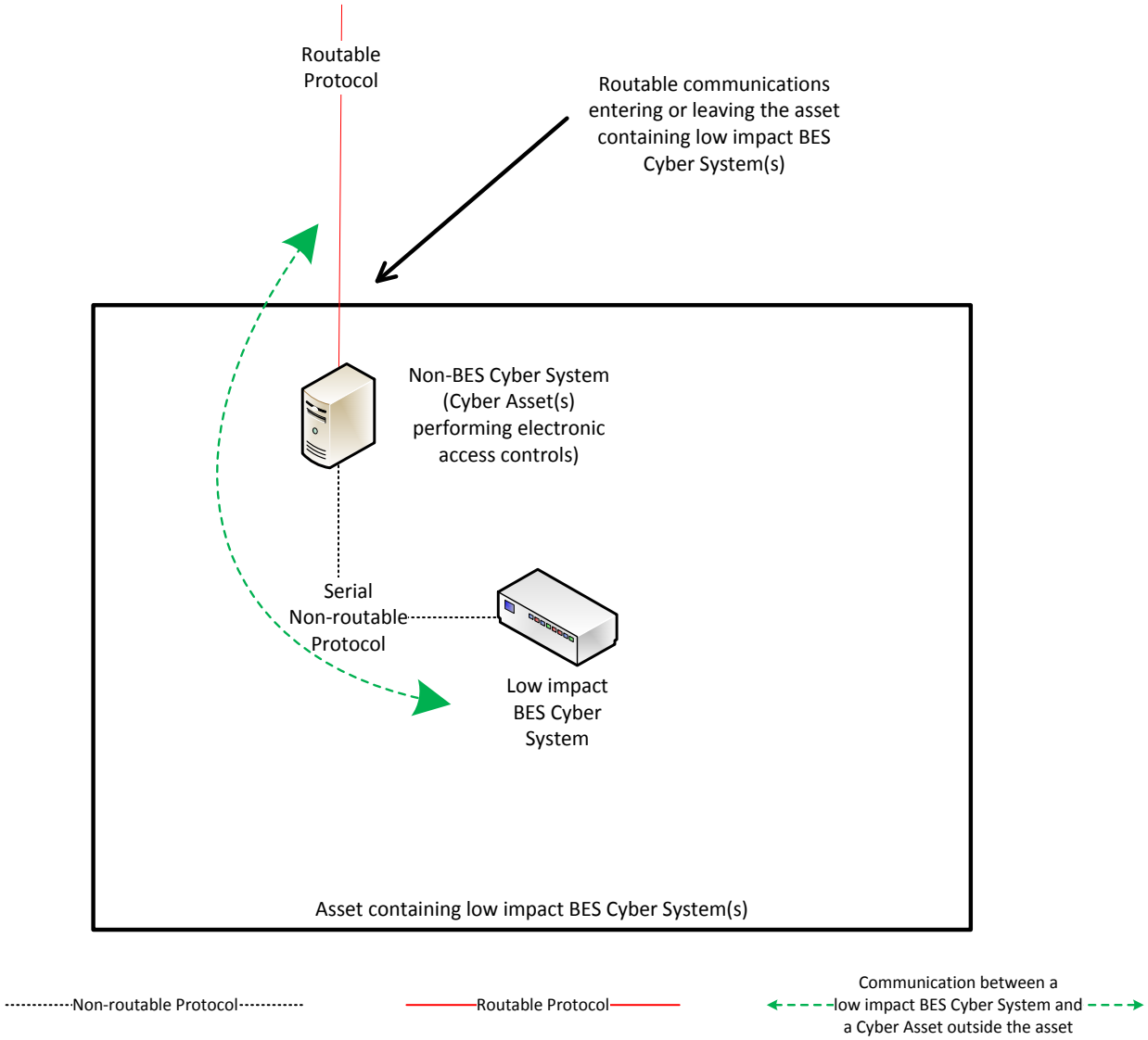
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a "one-way" (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.



Reference Model 4

Reference Model 5 – User Authentication

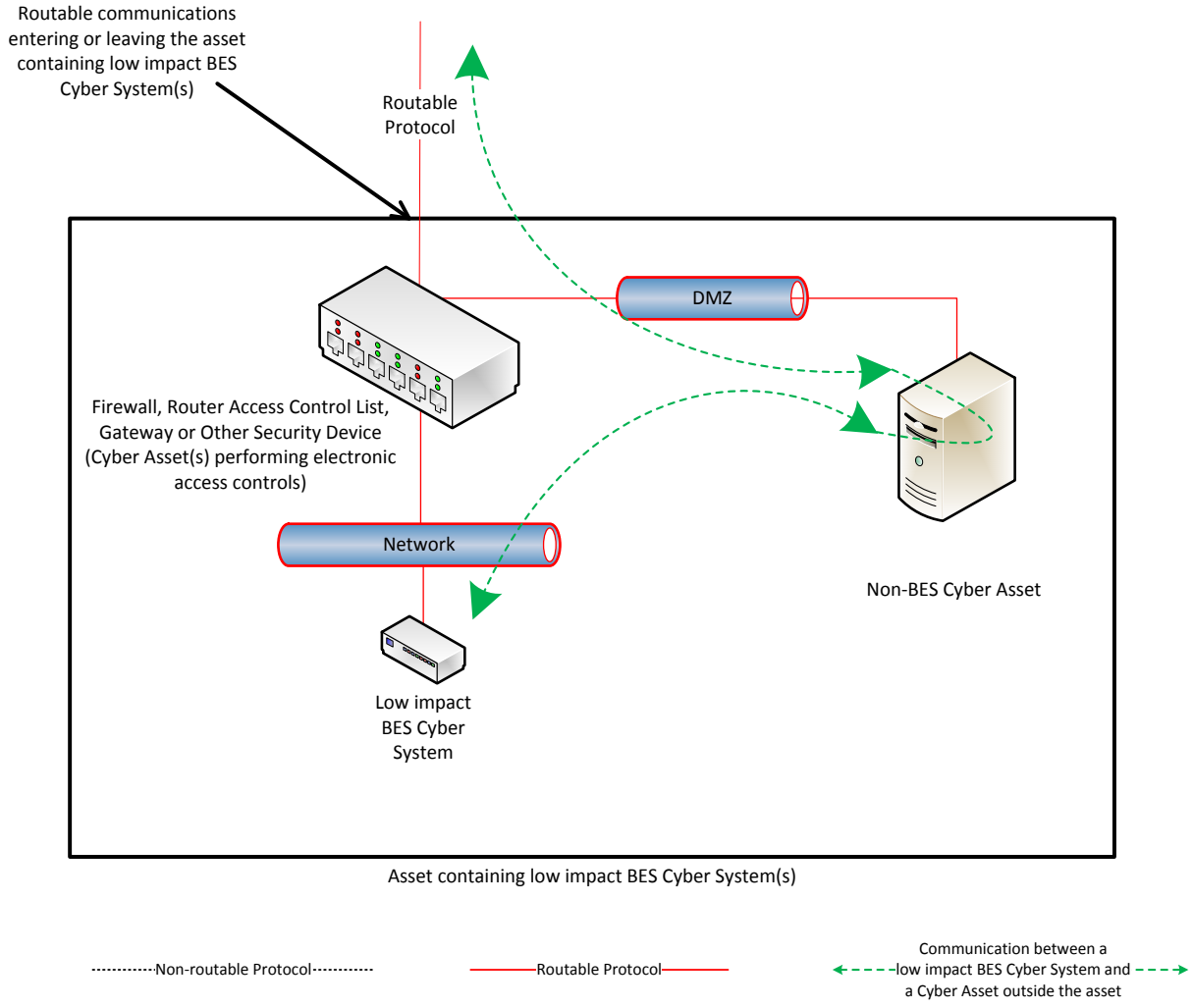
This reference model demonstrates that Responsible Entities have flexibility in choosing electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication is configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications would be controlled in this network architecture by permitting no communication to be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user-initiated interactive access.



Reference Model 5

Reference Model 6 – Indirect Access

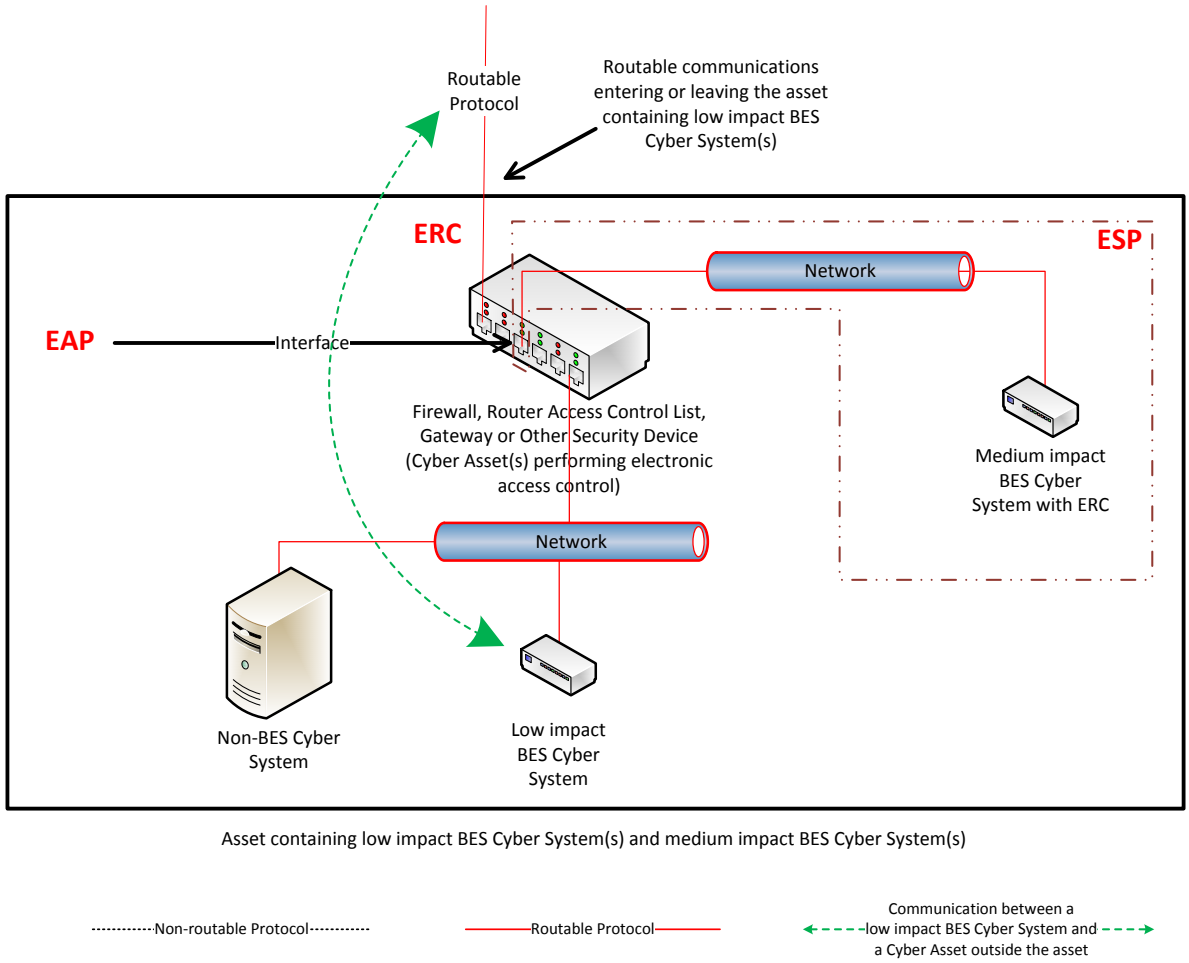
In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, it is intended that the Responsible Entity implement electronic access controls that permit only necessary inbound and outbound electronic access to the low impact BES Cyber System. Consistent with the other reference models provided, the electronic access in this reference model is controlled using the security device that is restricting the communication that is entering or leaving the asset.



Reference Model 6

Reference Model 7 – Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

In this reference model, there is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and External Routable Connectivity because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls for purposes of CIP-003. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.

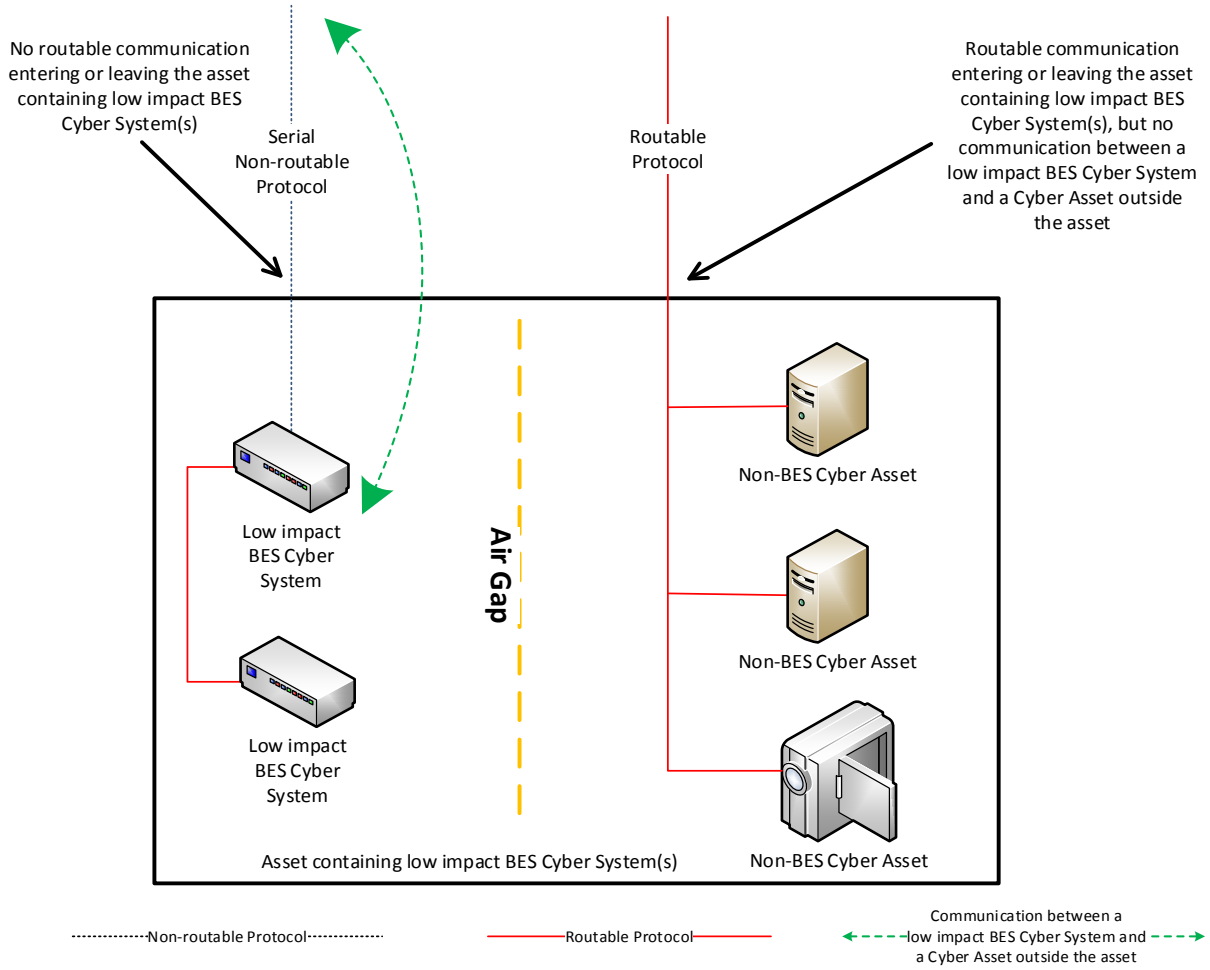


Reference Model 7

Reference Model 8 – Physical Isolation and Serial Non-routable Communications – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:

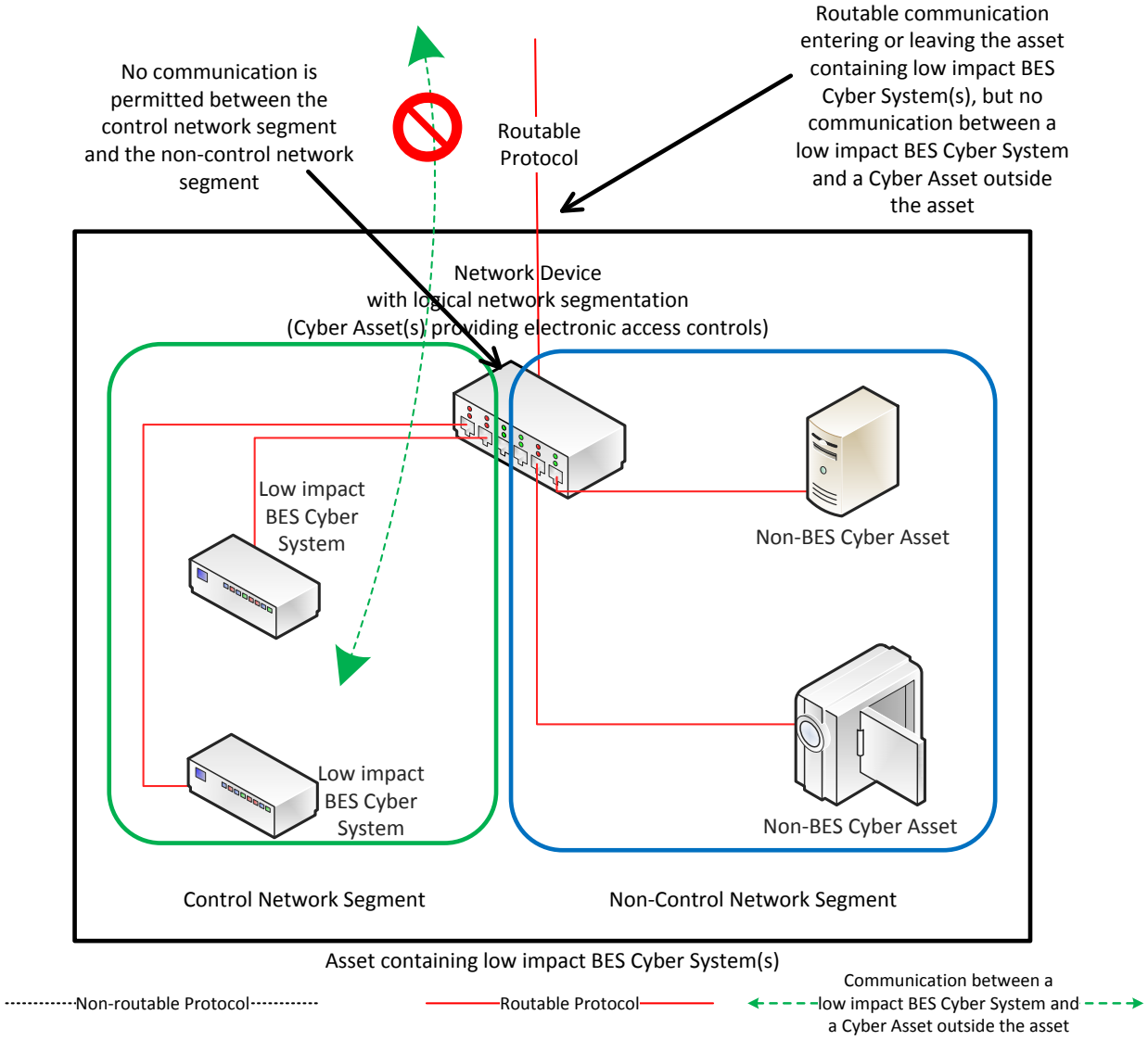
1) The physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;
2) The communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls.
3) The routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).



Reference Model 8

Reference Model 9 – Logical Isolation - No Electronic Access Controls Required

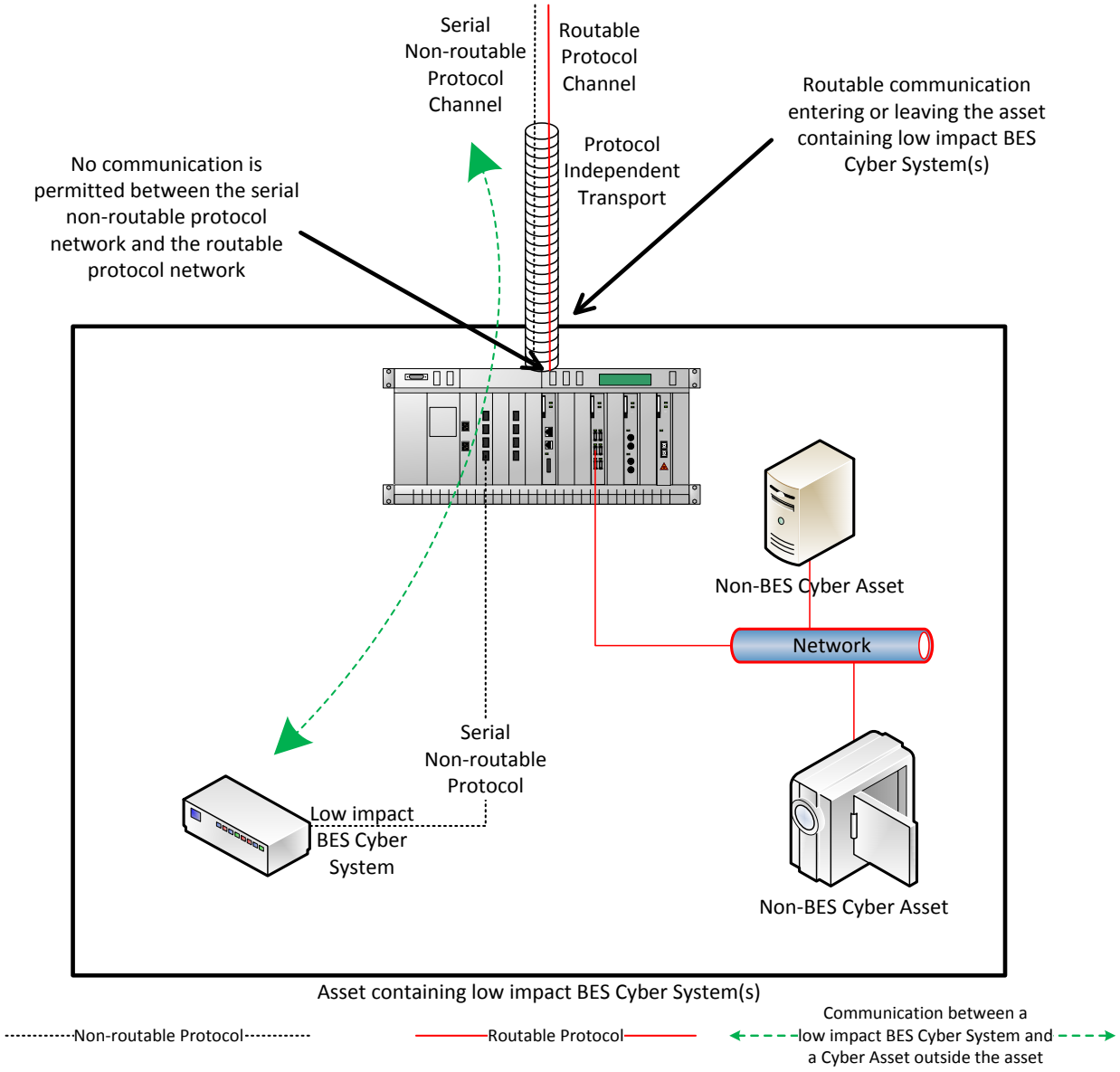
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

Reference Model 10 - Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a protocol independent transport that may carry routable and non-routable communication such as a Time-Division Multiplexing (TDM) network, a Synchronous Optical Network (SONET), or a Multiprotocol Label Switching (MPLS) network. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol.



Reference Model 10

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- A low impact BES Cyber System has a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of "controlling" inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity's response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, "A malicious act or suspicious event that disrupts, or was an attempt to

disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R2, Attachment 1, Section 5 – Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

Most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, and therefore Transient Cyber Assets and Removable Media are needed to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. Transient Cyber Assets and Removable Media are a potential means for cyber-attack. To protect the BES Cyber Assets and BES Cyber Systems, CIP-003 Requirement R2, Attachment 1, Section 5 requires Responsible Entities to document and implement a plan for how they will mitigate the risk of malicious code introduction to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document processes that are supportable within its organization and in alignment with its change management processes.

Transient Cyber Assets can be one of many types of devices from a specially-designed device for maintaining equipment in support of the BES to a platform such as a laptop, desktop, or tablet that may interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code to the BES Cyber Asset(s) or BES Cyber System(s). Note: Cyber Assets connected to a BES Cyber System for less than 30 days due to an unplanned removal, such as premature failure, are not intended to be identified as Transient Cyber Assets. Removable Media subject to this requirement include, among others, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Examples of these temporarily connected devices include, but are not limited to:

- Diagnostic test equipment;
- Equipment used for BES Cyber System maintenance; or
- Equipment used for BES Cyber System configuration.

To meet the objective of mitigating risks associated with the introduction of malicious code at low impact BES Cyber Systems, Section 5 specifies the capabilities and possible security methods available to Responsible Entities based upon asset type and ownership.

With the list of options provided in Attachment 1, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset or BES Cyber Asset.

Malicious Code Risk Mitigation

The terms “mitigate”, “mitigating”, and “mitigation” are used in Section 5 in Attachment 1 to address the risks posed by malicious code when connecting Transient Cyber Assets and Removable Media to BES Cyber Systems. Mitigation is intended to mean that entities reduce security risks presented by connecting the Transient Cyber Asset or Removable Media. When determining the method(s) to mitigate the introduction of malicious code, it is not intended for entities to perform and document a formal risk assessment associated with the introduction of malicious code.

Per Transient Cyber Asset Capability

As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of “per Transient Cyber Asset capability” is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R2, Attachment 1, Section 5.1 - Transient Cyber Asset(s) Managed by the Responsible Entity

For Transient Cyber Assets and Removable Media that are connected to both low impact and medium/high impact BES Cyber Systems, entities must be aware of the differing levels of requirements and manage these assets under the program that matches the highest impact level to which they will connect.

Section 5.1: Entities are to document and implement their plan(s) to mitigate malicious code through the use of one or more of the protective measures listed, based on the capability of the Transient Cyber Asset.

The Responsible Entity has the flexibility to apply the selected method(s) to meet the objective of mitigating the introductions of malicious code either in an on-going or in an on-demand manner. An example of managing a device in an on-going manner is having the antivirus solution for the device managed as part of an end-point security solution with current signature or pattern updates, regularly scheduled systems scans, etc. In contrast, for devices that are used infrequently and the signatures or patterns are not kept current, the entity may manage those devices in an on-demand manner by requiring an update to the signatures or patterns and a scan of the device before the device is connected to ensure that it is free of malicious code.

Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

The following is additional discussion of the methods to mitigate the introduction of malicious code.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to update the signatures or patterns and scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the risk that malicious software could execute on the Transient Cyber Asset and impact the BES Cyber Asset or BES Cyber System.
- When using methods other than those listed, entities need to document how the other method(s) meet the objective of mitigating the risk of the introduction of malicious code.

If malicious code is discovered on the Transient Cyber Asset, it must be mitigated prior to connection to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. An entity may choose to not connect the Transient Cyber Asset to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

Requirement R2, Attachment 1, Section 5.2 - Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

Section 5 also recognizes the lack of direct control over Transient Cyber Assets that are managed by parties other than the Responsible Entity. This lack of control, however, does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to mitigate the introduction of malicious code to low impact BES Cyber System(s) from Transient Cyber Assets it does not manage. Section 5 requires entities to review the other party's security practices with respect to Transient Cyber Assets to help meet the objective of the requirement. The use of "prior to connecting the Transient Cyber Assets" is intended to ensure that the Responsible Entity conducts the review before the first connection of the Transient Cyber Asset to help meet the objective to mitigate the introduction of malicious code. The SDT does not intend for the Responsible Entity to conduct a review for every single connection of that Transient Cyber Asset once the Responsible Entity has established the Transient Cyber Asset is meeting the security objective. The intent is to not require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

To facilitate these controls, Responsible Entities may execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity Procurement Language for Energy Delivery dated April 2014.[1] Procurement language may unify

[1] http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014

the other party and entity actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back up recovery may be part of the other party's support. Entities may consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.

Section 5.2.1: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.

- Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.
- Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.
- Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This method intends to reduce the attack surface on the Transient Cyber Asset and reduce the avenues by which malicious software could be introduced.

Section 5.2.2: The intent of this section is to ensure that after conducting the selected review from Section 5.2.1, if there are deficiencies identified, actions mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems must be completed prior to connecting the device(s) to an applicable system.

Requirement R2, Attachment 1, Section 5.3 - Removable Media

Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.

Section 5.3: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the

BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that can be incorporated into a plan to mitigate the risk of malicious code. The SDT does not intend to obligate a Responsible Entity to conduct a review for every single connection of Removable Media, but rather to implement its plan(s) in a manner that protects all BES Cyber Systems where Removable Media may be used. The intent is to not require a log documenting each connection of Removable Media to a BES Cyber Asset.

As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 5.3.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System.

Requirement R3:

The intent of CIP-003-8, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-8, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to

the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers five subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; (4) Cyber Security Incident response; and (5) Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "…the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6…to provide needed clarity to the definition

and eliminate ambiguity surrounding the term 'direct' as it is used in the proposed definition…within one year of the effective date of this Final Rule."

The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the following exclusion language (previously in the definition of LERC) contained in romanette (iii): "not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)".

The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to "the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any." The focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.

Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.

Rationale for Section 5 of Attachment 1 (Requirement R2):
Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 32 of FERC Order No. 822, the Commission directed NERC to "…provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability." Transient devices are potential vehicles for introducing malicious code into low impact BES Cyber Systems. Section 5 of Attachment 1 is intended to mitigate the risk of malware propagation to the BES through low impact BES Cyber Systems by requiring entities to develop and implement one or more plan(s) to address the risk. The cyber security plan(s) along with the cyber security policies required under Requirement R1, Part 1.2, provide a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP Senior Manager to be a "corporate officer or equivalent" would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for "clear lines of authority and ownership for security matters." With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

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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 the violation risk factor (VRF) and violation severity levels (VSLs) for Requirements R1 and R2 in proposed NERC Reliability Standard CIP-003-8 — Cyber Security — Security Management Controls. 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 VRF
s 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.

- **Requirement R1: No changes made to the VRF or VSL.**
- **Requirement R2: No changes made to the VRF or VSL.**
- **Requirement R3: No changes made to the VRF or VSL.**
- **Requirement R4: No changes made to the VRF or VSL.**

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-003-8 - Cyber Security – Security Management Controls

Applicable Standard

- Reliability Standard CIP-003-8 - Cyber Security – Security Management Controls

Requested Retirements

- Reliability Standard CIP-003-7 - Cyber Security – Security Management Controls

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On April 19, 2018, the Federal Energy Regulatory Commission (the "Commission") issued Order No. 843, approving CIP-003-7. In that Order, the Commission also directed NERC to "develop and submit modifications to Reliability Standard CIP-003-7 to include an explicit requirement that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices."

Effective Dates

Reliability Standard CIP-003-8

Where approval by an applicable governmental authority is required, Reliability Standard CIP-003-8 shall become effective on the later of (1) January 1, 2020, or (2) 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 standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-003-8 shall become effective on the later of (1) January 1, 2020, or (2) the first day of the first

calendar quarter that is six (6) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-003-7

Reliability Standard CIP-003-7 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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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

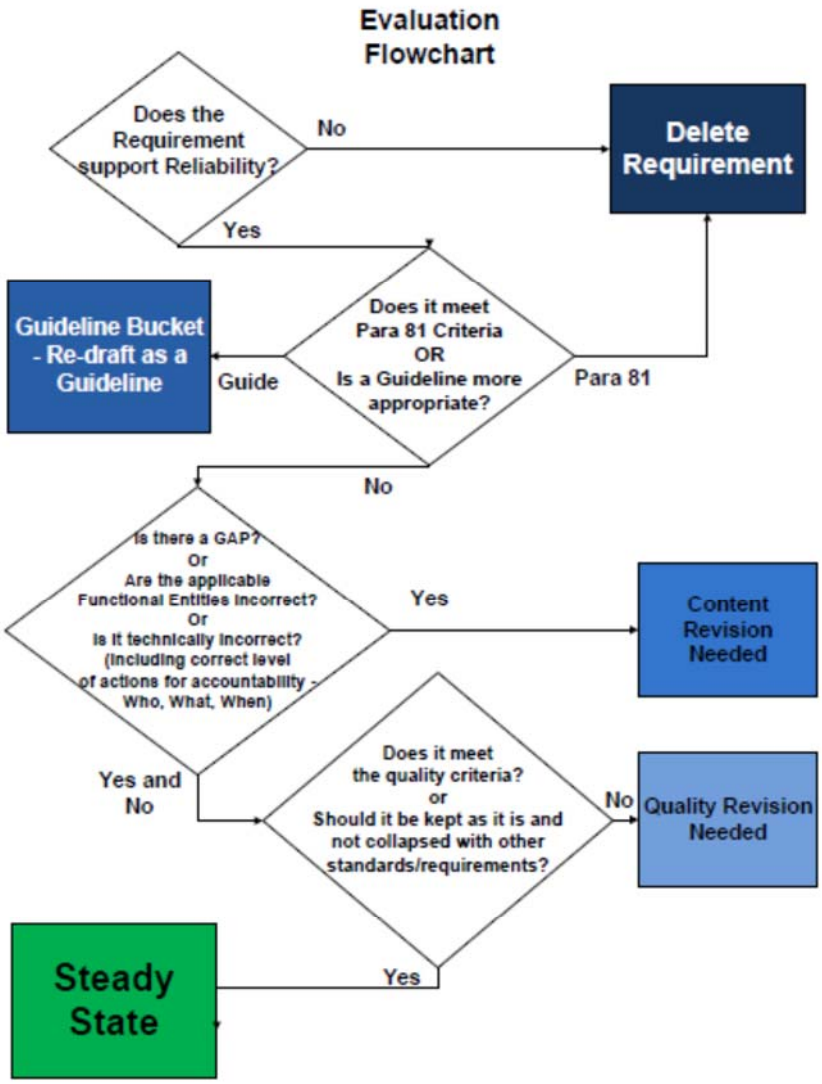


Figure 1: Evaluation Flow Chart

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)

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

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

45-day formal comment period with initial ballot

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	06/13/18
SAR posted for comment	03/30/18 – 04/30/18
28-day informal comment period	08/10/18 – 09/06/18

Anticipated Actions	Date
45-day formal or informal comment period with initial ballot	October 2018 – November 2018
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	February 2019

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.

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~2~~3

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

   4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-~~2~~3.

Background: During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of that in TPL-007-2.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments*. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1*. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

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.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. 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 actions.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

GMD Measurement Data Processes

R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

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.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

- For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for 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.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. 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.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

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, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in Canada.

All references to "Attachment 1" in the standard are replaced with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_{\,b}\ (V/km) \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_{\,s}\ (V/km) \quad (2)$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \quad (3)$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

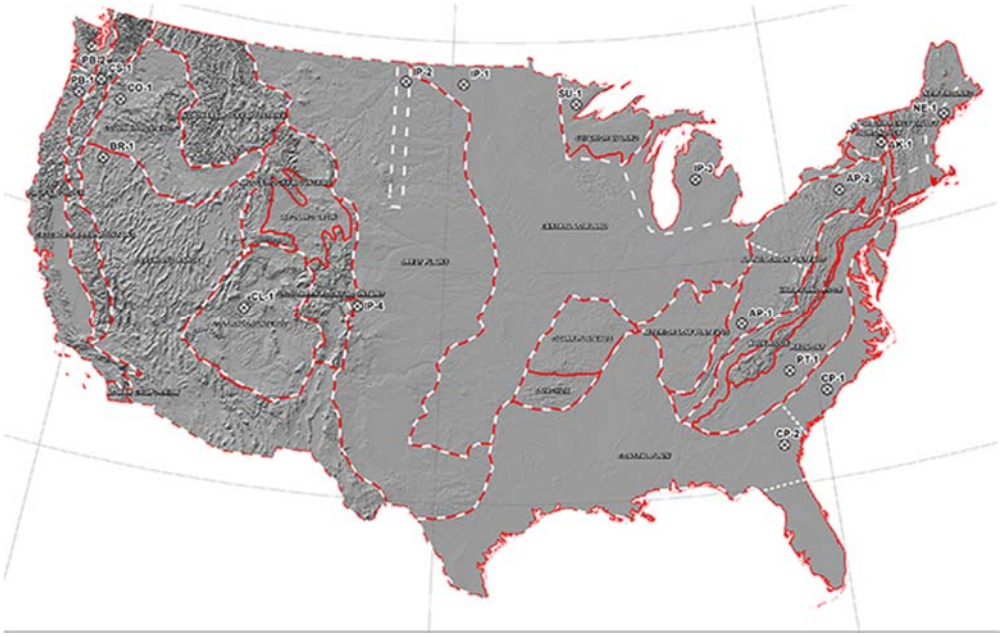


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Rationale: Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated based on the earth model published on the USGS public website.

Table 4: Reference Earth Model (Quebec)

Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

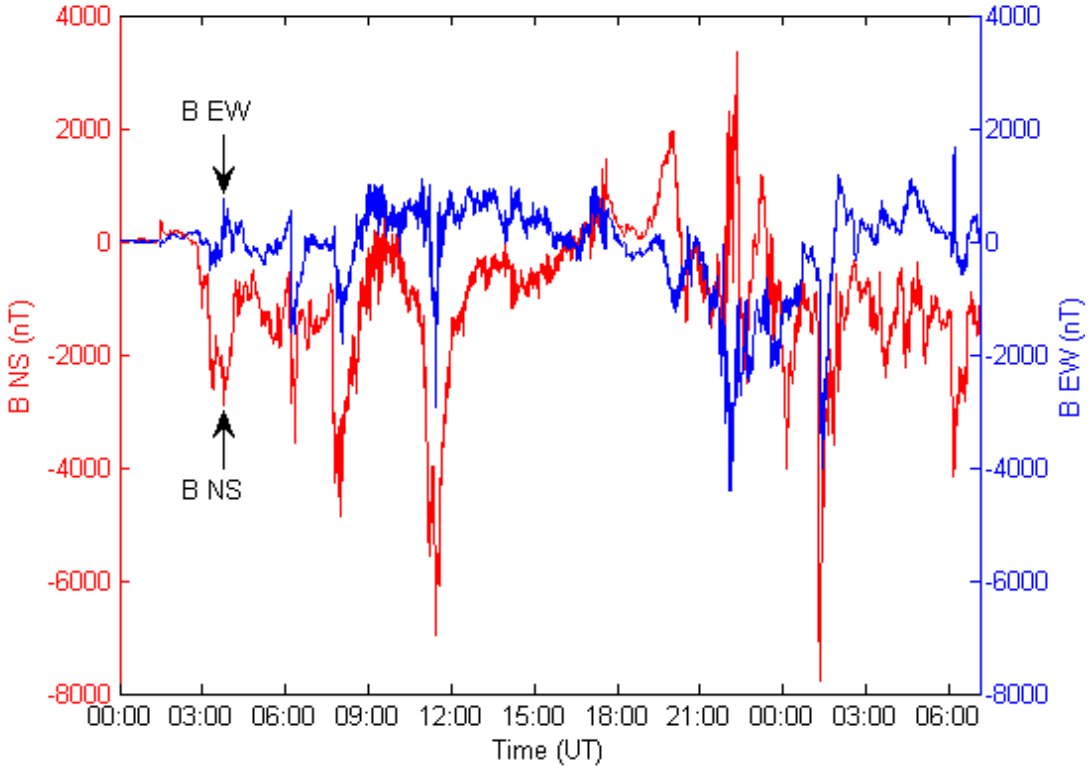


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

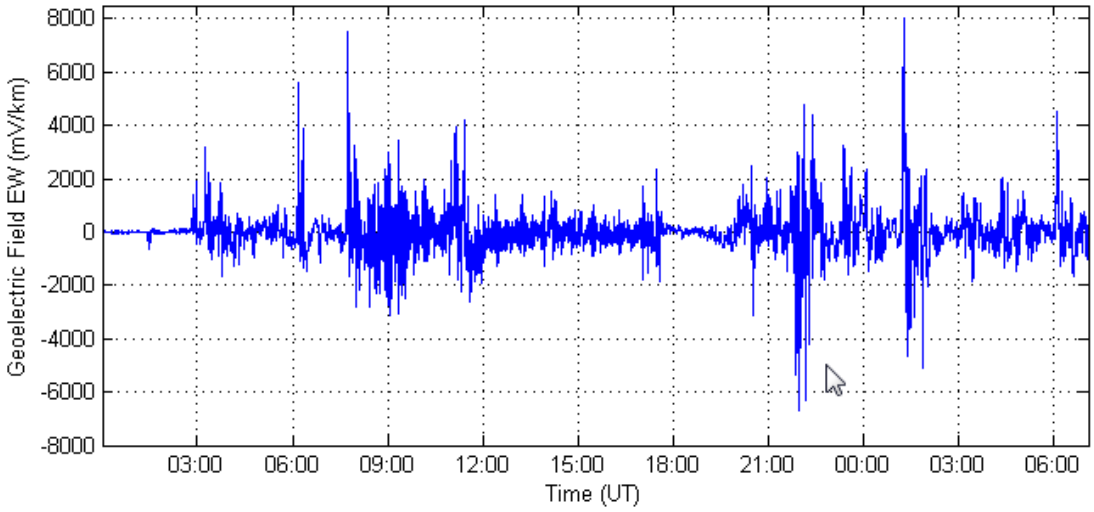


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

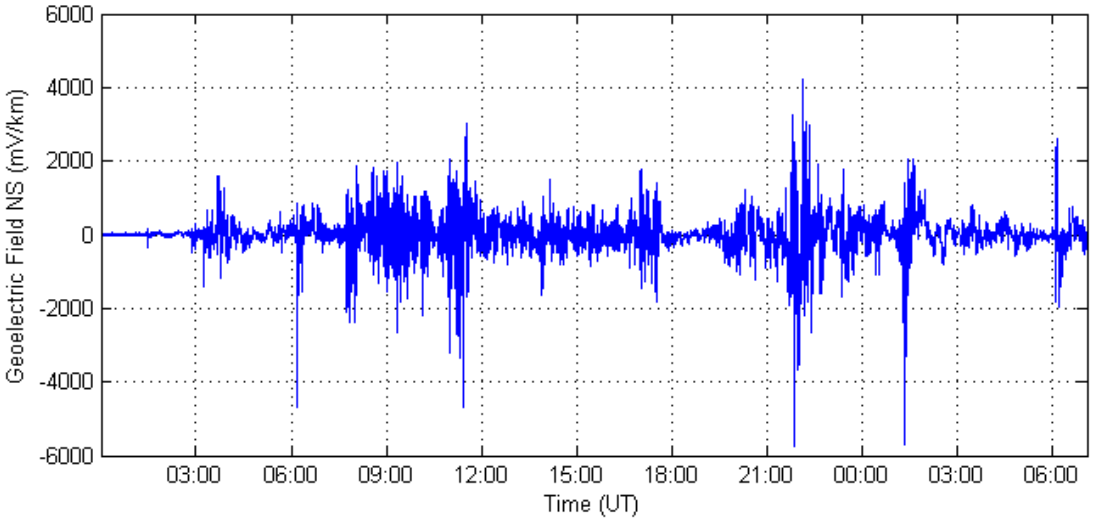


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

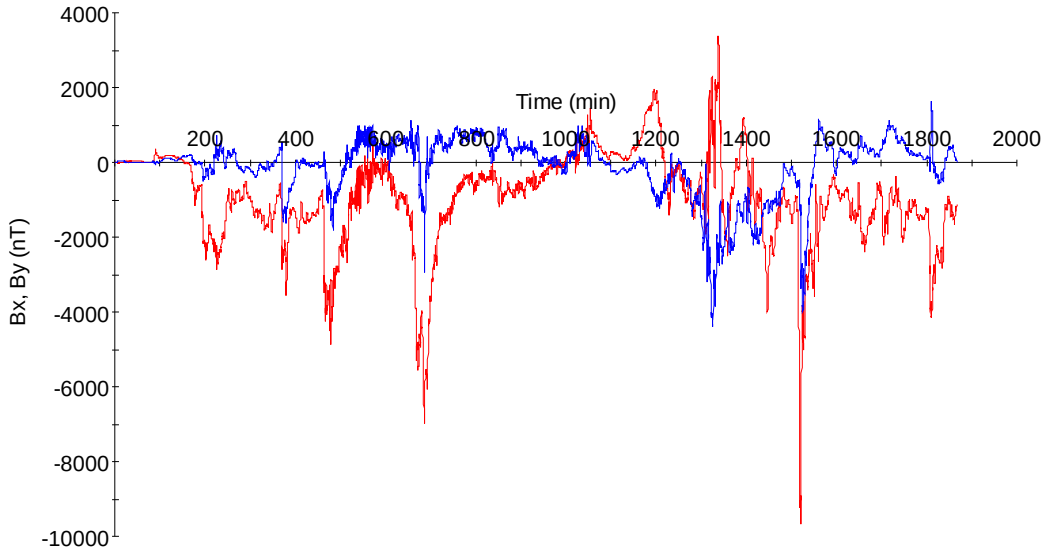


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

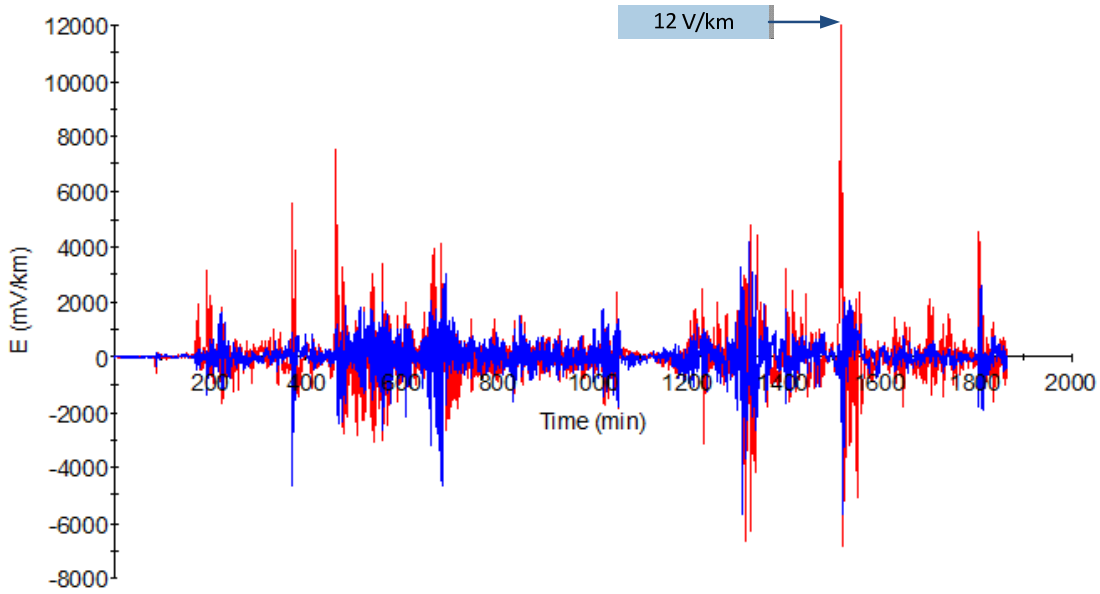


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that any Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

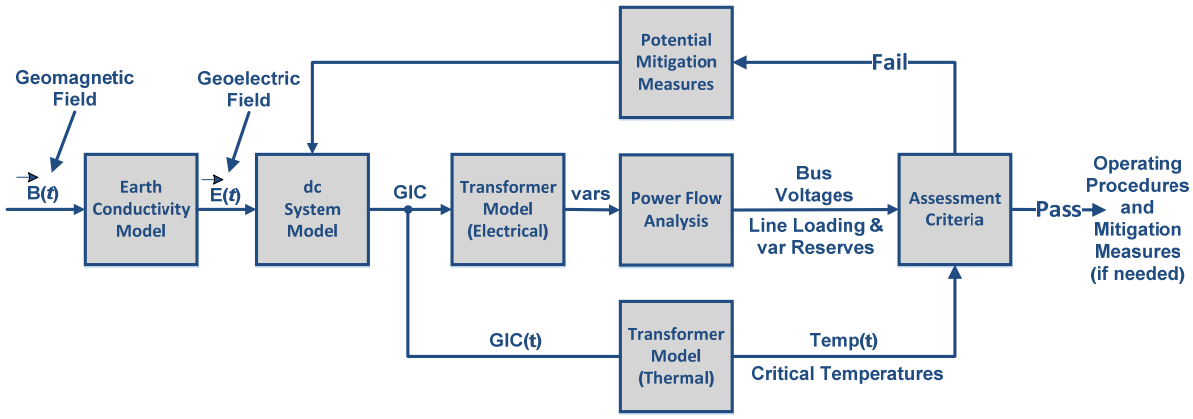
For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016[11] white paper includes the event description, analysis, and example calculations.

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017[12] white paper includes the event description and analysis.

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*, December 2013.[13]

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not

[11] http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[12] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *Geomagnetic Disturbance Planning Guide*,[14] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.

Requirement R5

The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time-series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the *Transformer Thermal Impact Assessment White Paper*,[15] October 2017.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[16] for this requirement. This ERO-Endorsed document is posted on the NERC Compliance Guidance[17] webpage.

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[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[15] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[16] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.
[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx.

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[18] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*,[19] December 2013. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[20] February 2012.

Requirement R8

The *Geomagnetic Disturbance Planning Guide*,[21] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be

[18] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[19] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[20] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.
[21] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.

needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[22] discussed in the Requirement R6 section above. A later version of the *Transformer Thermal Impact Assessment White Paper*,[23] October 2017, has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment.

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[24] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R11

Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*, [25] February 2012. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful for model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system

[22] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.
[23] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[24] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[25] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.

studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.

- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

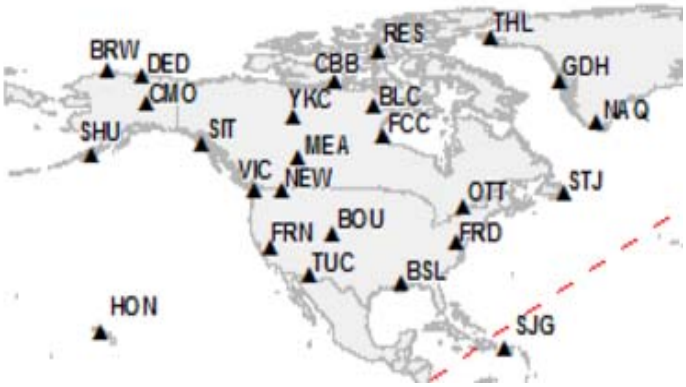
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:[26]



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012.[27]

[26] http://www.intermagnet.org/index-eng.php.
[27] http://www.intermagnet.org/publications/intermag_4-6.pdf.

Rationale

During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System*,[28] December 2013, developed by the NERC GMD Task Force.

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (Docket No. RM12-1-000). NERC guidelines require consistency among Reliability Standards.

[28] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

Rationale for R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The *Geomagnetic Disturbance Planning Guide*,[29] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*,[30] October 2017.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but

[29] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[30] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[31] October 2017.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper*,[32] October 2017.

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:

The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part

[31] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[32] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

7.3. Examples of situations beyond the control of the of the responsible entity (see Section 7.4) include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or

Delays resulting from the inability to acquire necessary Right-of-Way.

Rationale for Table 3:

Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74. [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

Rationale for R8 – R10:

The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P 44, P 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Rationale for R11 – R12:

The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88; P. 90-92). GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R11 and R12, respectively. See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

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Implementation Plan

Project 2018-01 Canadian-Specific Revisions to TPL-007-2

Applicable Standard(s)

- TPL-007-3- Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement(s)

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events
- TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard(s)

None

Applicable Entities

- Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and
- Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

In January 2018, NERC submitted for regulatory approval Reliability Standard TPL-007-2. This standard was developed in response to certain directives of the United States Federal Energy Regulatory Commission (FERC) from Order No. 830 (September 22, 2016), approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan and directing certain modifications.

In May 2018, a Standard Authorization Request was submitted identifying a need for a Canadian-specific Variance to the TPL-007-2 standard. Specifically, the Standard Authorization Request sought to provide an option for Canadian Registered Entities to define alternative Benchmark GMD Events and/or Supplemental GMD Events specific to their unique topology.

Reliability Standard TPL-007-3 adds a Variance for Canadian entities. The Canadian Variance replaces, in its entirety, Requirement R7, Part 7.3 of the continent-wide standard for Canadian entities and adds an alternate methodology for GMD Vulnerability Assessments, as described in Attachment 1-CAN. None of the continent-wide Requirements have been changed.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard TPL-007-3

United States

The standard shall become effective on the later of: (1) the effective date of Reliability Standard TPL-007-2; or (2) the first day of the first calendar quarter after the date TPL-007-3 is adopted by the NERC Board of Trustees.

This implementation plan incorporates by reference the phased-in compliance dates of the TPL-007-2 implementation plan (see Attachment 1).

All Other Jurisdictions

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 three (3) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

This implementation plan incorporates by reference the phased-in compliance dates of the TPL-007-2 implementation plan (see Attachment 1), except that the phased-in compliance dates described therein shall be based on the effective date of TPL-007-3.

Attachment 1-
TPL-007-2 Implementation Plan

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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation
Reliability Standard TPL-007-2

Applicable Standard

- TPL-007-2 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

General Considerations

This Implementation Plan is intended to integrate the new requirements in TPL-007-2 with the GMD Vulnerability Assessment process that is being implemented through approved TPL-007-1. At the time of the May 2018 filing deadline, many requirements in approved standard TPL-007-1 that lead

to completion of the geomagnetic disturbance (GMD) Vulnerability Assessment will be in effect. Furthermore, many entities may be taking steps to complete studies or assessments that are required by future enforceable requirements in TPL-007-1. The Implementation Plan phases in the requirements in TPL-007-2 based on the effective date of TPL-007-2, as follows:

- **Effective Date before January 1, 2021**. Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

- **Effective Date on or after January 1, 2021**. Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Standard TPL-007-2

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 three (3) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

If TPL-007-2 becomes effective before January 1, 2021

Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

Compliance Date for TPL-007-2 Requirements R1 and R2

Entities shall be required to comply with Requirements R1 and R2 upon the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R5
Entities shall not be required to comply with Requirements R5 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R11 and R12
Entities shall not be required to comply with Requirements R11 and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R6 and R10
Entities shall not be required to comply with Requirements R6 and R10 until 30 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3, R4, and R8
Entities shall not be required to comply with Requirements R3, R4, and R8 until 42 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R7
Entities shall not be required to comply with Requirement R7 until 54 months after the effective date of Reliability Standard TPL-007-2.

If TPL-007-2 becomes effective on or after January 1, 2021

Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Compliance Date for TPL-007-2 Requirements R1, R2, R5, and R6
Entities shall be required to comply with Requirements R1, R2, R5, and R6 upon the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3 and R4
Entities shall not be required to comply with Requirements R3 and R4 until 12 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R7, R11, and R12
Entities shall not be required to comply with Requirements R7, R11, and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until 36 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R10
Entities shall not be required to comply with Requirement R10 until 60 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R8
Entities shall not be required to comply with Requirement R8 until 72 months after the effective date of Reliability Standard TPL-007-2.

Retirement Date

Standard TPL-007-1
Reliability Standard TPL-007-1 shall be retired immediately prior to the effective date of TPL-007-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

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Violation Risk Factor and Violation Severity Level Justifications

TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

The Project 2018-01 Standard Drafting Team reviewed the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) and determined that no modifications to the VRFs and VSLs are necessary for the proposed TPL-007-3 (Canadian Variance). Since the VRFs and VSLs do not require modifications, the applicable justifications for those VRFs and VSLs will also remain the same as applied to the proposed TPL-007-2 (Canadian Variance).

- TPL-007-2 VRF and VSL Justifications

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 proposed standard for formal 20-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 9, 2018
SAR posted for comment	August 10 – September 10, 2018

Anticipated Actions	Date
20-day formal comment period with ballot	October 2018
15-day formal comment period with additional ballot	November 2018
5-day final ballot	January 2019
Board adoption	February 2019

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.

Proposed Modified Terms:

Cyber Security Incident:

A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise, (1) the Electronic Security Perimeter or (2) Physical Security Perimeter or, (3) Electronic Access Control of Monitoring System for High or Medium Impact BES Cyber Systems, or;
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber system.

Reportable Cyber Security Incident:

A Cyber Security Incident that has compromised or disrupted:

- One or more reliability tasks of a functional entity; or
- Electronic Security Perimeter; or
- Electronic Access Control or Monitoring System (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting.

Proposed New Term:

Reportable Attempted Cyber Security Incident:

A Cyber Security Incident that was an attempt to compromise or disrupt:

- One or more reliability tasks of a functional entity; or
- Electronic Security Perimeter; or
- Electronic Access Control or Monitoring System (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting

~~B.~~

~~C.~~A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning

2. **Number:** CIP-008-65

3. **Purpose:** To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.

4. **Applicability:**

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

   4.1.1 Balancing Authority

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

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

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

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

   4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

   4.1.3 Generator Operator

4.1.4 Generator Owner

~~**4.1.5 Interchange Coordinator or Interchange Authority**~~

~~4.1.6~~4.1.5 Reliability Coordinator

~~4.1.7~~4.1.6 Transmission Operator

~~4.1.8~~4.1.7 Transmission Owner

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

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-008-~~6~~5:

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

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

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

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

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002~~-5~~ identification and categorization processes.

5. Effective Dates:

See Implementation Plan for CIP-008-6.~~1. **24 Months Minimum** – CIP-008-5 shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required, CIP-008-5 shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

Standard CIP-008~~-5~~ exists as part of a suite of CIP Standards related to cyber security. CIP-002~~-5~~ requires the initial identification and categorization of BES Cyber Systems. CIP-003~~-5~~, CIP-004~~-5~~, CIP-005~~-5~~, CIP-006~~-5~~, CIP-007~~-5~~, CIP-008~~-5~~, CIP-009~~-5~~, CIP-010~~-1~~, and CIP-011~~-1~~ require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, "*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*" The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements.

An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.
Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables:

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the "Applicable Systems" column as described.

- **High Impact BES Cyber Systems –** Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5 identification and categorization processes.
- **Medium Impact BES Cyber Systems –** Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5 identification and categorization processes.

~~D.~~B. Requirements and Measures

R1. Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications*. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].*

M1. Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications*.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	One or more processes to identify, classify, and respond to Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	One or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident ~~and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a Reportable Cyber Security Incident.~~or a Reportable Attempted Cyber Security Incident and requires notification per Requirement R4.	Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents ~~and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).~~ or Reportable Attempted Cyber Security Incidents and documented processes for notification.
1.3	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	The roles and responsibilities of Cyber Security Incident response groups or individuals.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.4	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Incident handling procedures for Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).

R2. Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].*

M2. Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Test each Cyber Security Incident response plan(s) at least once every 15 calendar months: • By responding to an actual Reportable Cyber Security Incident; • With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or • With an operational exercise of a Reportable Cyber Security Incident.	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.

CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident, Reportable Attempted Cyber Security Incident, or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise.	Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.
2.3	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Retain records related to Reportable Cyber Security Incidents and Reportable Attempted Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents and Reportable Attempted Cyber Security Incidents.

R3. Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

M3. Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*.

CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response: 3.1.1. Document any lessons learned or document the absence of any lessons learned; 3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and 3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.	An example of evidence may include, but is not limited to, all of the following: 1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned; 2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan: 3.2.1. Update the Cyber Security Incident response plan(s); and 3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.	An example of evidence may include, but is not limited to: 1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and 2. Evidence of plan update distribution including, but not limited to: • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

R4. Each Responsible Entity shall notify the Electricity Information Sharing and Analysis Center (E-ISAC) and each United States Responsible Entity also shall notify the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT), or their successors, of Reportable Cyber Security Incidents and Reportable Attempted Cyber Security Incidents, unless prohibited by law, according to each of the applicable requirement parts in *CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents*. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

M4. Evidence must include, but is not limited to, documentation that collectively demonstrates notification of each determined Reportable Cyber Security Incident according to the applicable requirement parts in *CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents.*

CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Except for Reportable Cyber Security Incidents compromising or disrupting a Physical Security Perimeter, initial notifications and updates shall include the following attributes, at a minimum, to the extent known: 1. The functional impact; 2. The attack vector used; and 3. The level of intrusion that was achieved or attempted.	Examples of evidence may include, but are not limited to, dated documentation of initial notifications and updates to the E-ISAC and ICS-CERT in the form of Attachment 1 submissions.

CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Responsible Entities shall use one of the following methods for initial notification: • Electronic submission of Attachment 1; • Phone; or • Email. If Attachment 1 was not submitted for initial notification, it must be submitted within 5 calendar days of initial notification, without attribute information if undetermined at the time of submittal.	Examples of evidence may include, but are not limited to, dated documentation of notices to the E-ISAC and ICS-CERT in the form of electronic submissions of Attachment 1, phone records or email.
4.3	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Timeline for initial notification: • One hour from the determination of a Reportable Cyber Security Incident. • By the end of the next calendar day after a determination of a Reportable Attempted Cyber Security Incident.	Examples of evidence may include, but are not limited to, dated documentation of notices to the E-ISAC and ICS-CERT in the form of phone records for preliminary notice or submissions through the E-ISAC and ICS-CERT approved methods, or Attachment 1 submissions.

CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.4	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Responsible Entities shall submit Attachment 1 updates for the attributes required in Part 4.1 within 5 calendar days of determination of new or changed attribute information. Submissions must occur each time new attribute information is available until all attributes have been reported.	Examples of evidence may include, but are not limited to, dated documentation of Attachment 1 submissions to the E-ISAC and ICS-CERT.

~~E.~~C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long Term Planning**	**Lower**	N/A	N/A	The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3) OR The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4)	The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents or Reportable Attempted Cyber Security Incidents. (1.2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~The Responsible Entity has developed a Cyber Security Incident response plan, but did not provide at least preliminary notification to ES-ISAC within one hour from identification of a Reportable Cyber Security Incident. (1.2)~~
R2	**Operations Planning** **Real-time Operations**	**Lower**	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 15 calendar months, not exceeding 16 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not exceeding 18 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 18 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents or Reportable Attempted

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Security Incident or Reportable Attempted Cyber Security Incident occurs. (2.2)	Cyber Security Incidents. (2.3)
R3	**Operations Assessment**	**Lower**	The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)	The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1) OR The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3) OR The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2) • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or	response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2) • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes.	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Technology changes.		
R4	Operations Assessment	Lower	The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident and the attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to submit the form in Attachment 1. (4.4) OR The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident and the	The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes within the timeframes pursuant to Requirement R4, Part 4.4 after determination of the attribute(s) not reported pursuant to Requirement R4, Part 4.1. (4.4) OR The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a	The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, but failed to notify or update E-ISAC or ICS-CERT, or their successors, within the timeframes pursuant to Requirement R4, Part 4.3.	The Responsible Entity failed to notify E-ISAC or ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident. (R4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to use one of the methods for initial notification pursuant to Requirement R4, Part 4.2.	Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes after determination of the attribute pursuant to Requirement R4, Part 4.1.		

~~F.~~D. Regional Variances

None.

~~G.~~E. Interpretations

None.

~~H.~~F. Associated Documents

None.

Guidelines and Technical Basis

Note: The Guidelines and Technical Basis section has not been revised as part of Project 2018-02. A separate technical rationale document has been created to cover Project 2018-02 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5's categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf
- National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing

characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

Requirement R2:

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.

Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

Requirement R3:

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

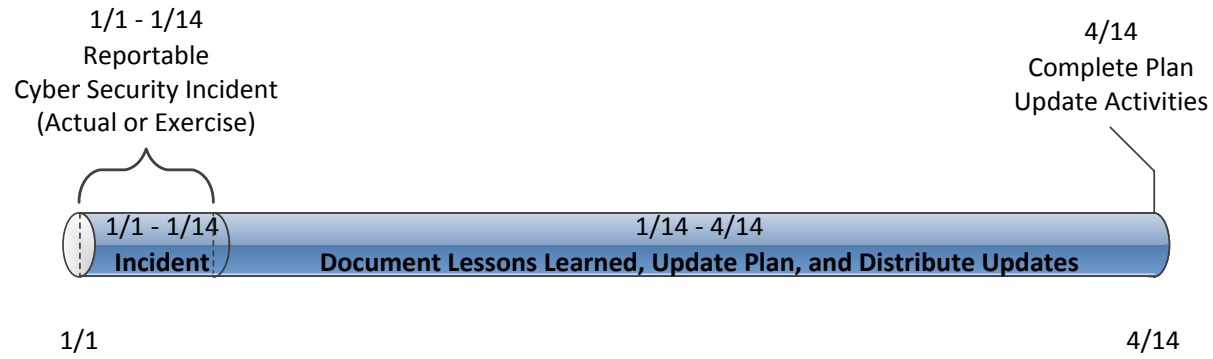

Figure 1: CIP-008-5 R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

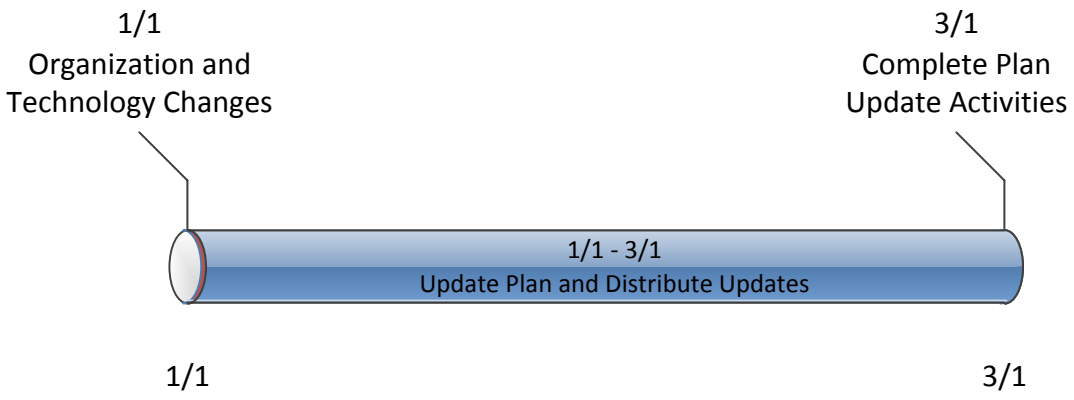

Figure 2: Timeline for Plan Changes in 3.2

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.

Summary of Changes: Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

Reference to prior version: (Part 1.1) CIP-008, R1.1

Change Description and Justification: (Part 1.1)

"Characterize" has been changed to "identify" for clarity. "Response actions" has been changed to "respond to" for clarity.

Reference to prior version: (Part 1.2) CIP-008, R1.1

Change Description and Justification: (Part 1.2)

Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).

Reference to prior version: (Part 1.3) CIP-008, R1.2

Change Description and Justification: (Part 1.3)

Replaced incident response teams with incident response "groups or individuals" to avoid the interpretation that roles and responsibilities sections must reference specific teams.

Reference to prior version: (Part 1.4) CIP-008, R1.2

Change Description and Justification: (Part 1.4)
Conforming change to reference new defined term Cyber Security Incidents.

Rationale for R2:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

Summary of Changes: Added testing requirements to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

Reference to prior version: (Part 2.1) CIP-008, R1.6

Change Description and Justification: (Part 2.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-008, R1.6

Change Description and Justification: (Part 2.2)

Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.

Reference to prior version: (Part 2.3) CIP-008, R2

Change Description and Justification: (Part 2.3)

Removed references to the retention period because the Standard addresses data retention in the Compliance Section.

Rationale for R3:

Conduct sufficient reviews, updates and communications to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.

Summary of Changes: Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

Reference to prior version: (Part 3.1) CIP-008, R1.5

Change Description and Justification: (Part 3.1)

Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.

Reference to prior version: (Part 3.2) CIP-008, R1.4

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity.	

		Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-008-5.	
5	7/9/14	FERC Letter Order issued approving VRFs and VSLs revisions to certain CIP standards.	CIP-008-5 Requirement R2, VSL table under Severe, changed from 19 to 18 calendar months.
6	10/4/18	Modified to address directives in FERC Order No. 848	

CIP-008-6 - Attachment 1

Cyber Security Incident Reporting Form

Use this form to report Reportable Cyber Security Incidents and Reportable Attempted Cyber Security Incidents in accordance with CIP-008-6, Requirement R4.

Contact Information	
Name:	Click or tap here to enter text.
Phone Number:	Click or tap here to enter text.

Incident Type

☐ Reportable Cyber Security Incident

☐ Reportable Attempted Cyber Security Incident

Reporting Category

☐ Initial Notification

☐ Update

Required Attribute Information

1. Attack Vector ☐ Initial ☐ Update

Click or tap here to enter text.

2. Functional Impact ☐ Initial ☐ Update

Click or tap here to enter text.

3. Level of Intrusion ☐ Initial ☐ Update

CIP-008-6 - Attachment 2

Cyber Security Incident Reporting Form Instructions

Attachment 2 provides instructions to aid in the completion of Attachment 1.

CIP-008-6– Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
Contact Information	**Name**	Enter the First and Last Name of the Responsible Entity's primary point of contact for the reported incident.
	Phone Number	Enter the Phone Number(s) of the Responsible Entity's primary point of contact for the reported incident.
Incident Type	**Reportable Cyber Security Incident**	Check this box if Attachment 1 includes information for a Reportable Cyber Security Incident.
	Reportable Attempted Cyber Security Incident	Check this box if Attachment 1 includes information for a Reportable Attempted Cyber Security Incident. Note: Do not check this box for incidents related solely to a PSP(s).
Reporting Category	**Initial Notification**	Check this box if Attachment 1 is being submitted to satisfy initial notification obligations of Requirement R4 Part 4.2.
	Update	Check this box if Attachment 1 is being submitted to satisfy subsequent follow-up or update obligations of Requirement R4 Part 4.2.
Required Attribute Information (Attack Vector fields)	**Attack Vector**	• If known, enter a narrative description of the Attack Vector for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, malware, use of stolen credentials, etc.*
	Attack Vector Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Attack Vector Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.

CIP-008-6– Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
Required Attribute Information (Functional Impact fields)	**Functional Impact**	• If known, enter a narrative description of the functional impact for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, situational awareness, dynamic response, ability to perform Real-time Assessments, or Real-time monitoring etc.*
	Functional Impact Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Functional Impact Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.
Required Attribute Information (Level of Intrusion fields)	**Level of Intrusion**	• If known, enter a narrative description of the level of intrusion for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, whether the compromise or attempt to compromise occurred on Applicable Systems outside the Electronic Security Perimeter (ESP), at the ESP, or inside the ESP. Additionally, level of intrusion may include the Applicable System impact level and Cyber Asset classification level.*
	Level of Intrusion Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Level of Intrusion Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.

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Implementation Plan

Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting | Reliability Standard CIP-008-6

Applicable Standard

- CIP-008-6 – Cyber Security – Incident Reporting and Response Planning

Requested Retirement

- CIP-008-5 – Cyber Security – Incident Reporting and Response Planning

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective: None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

New Terms in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition:
Reportable Attempted Cyber Security Incident:
A Cyber Security Incident that was an attempt to compromise or disrupt:

- One or more reliability tasks of a functional entity; or
- Electronic Security Perimeter; or

- Electronic Access Control or Monitoring System (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting

Proposed Modified Definitions:
Cyber Security Incident:
A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise, (1) the Electronic Security Perimeter, (2) or Physical Security Perimeter, or (3) Electronic Access Control or Monitoring System for High or Medium Impact BES Cyber Systems, or
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Reportable Cyber Security Incident:
A Cyber Security Incident that has compromised or disrupted:

- One or more reliability tasks of a functional entity; or
- Electronic Security Perimeter; or
- Electronic Access Control or Monitoring System (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting

Proposed Retirements of Approved Definitions:
Cyber Security Incident:
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.

Reportable Cyber Security Incident:
A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.

Background

The purpose of this project is to address the directives issued by FERC in Order No. 848 to augment mandatory reporting of Cyber Security Incidents, including attempted Cyber Security Incidents 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)." (Order No. 848 at P1)

Proposed Reliability Standard CIP-008-6 addresses 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).

Effective Date

Reliability Standard CIP-008-6

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 12 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, the standard shall become effective on the first day of the first calendar quarter that is 12 calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition

Where approval by an applicable governmental authority is required, the definition shall become effective on the first day of the first calendar quarter that is 12 calendar months after the effective date of the applicable governmental authority's order approving Reliability Standard CIP-008-6, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is 12 calendar months after the date that Reliability Standard CIP-008-6 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-008-5

Reliability Standard CIP-008-5 shall be retired immediately prior to the effective date of Reliability Standard CIP-008-6 in the particular jurisdiction in which the revised standard is becoming effective.

Definition

The definitions proposed for retirement shall be retired immediately prior to the effective date of Reliability Standard CIP-008-6 in the particular jurisdiction in which the revised standard is becoming effective.

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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.

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Standard Processes Manual

VERSION ~~3~~4

Effective ~~June 26, 2013~~TBD

RELIABILITY | ACCOUNTABILITY

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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.

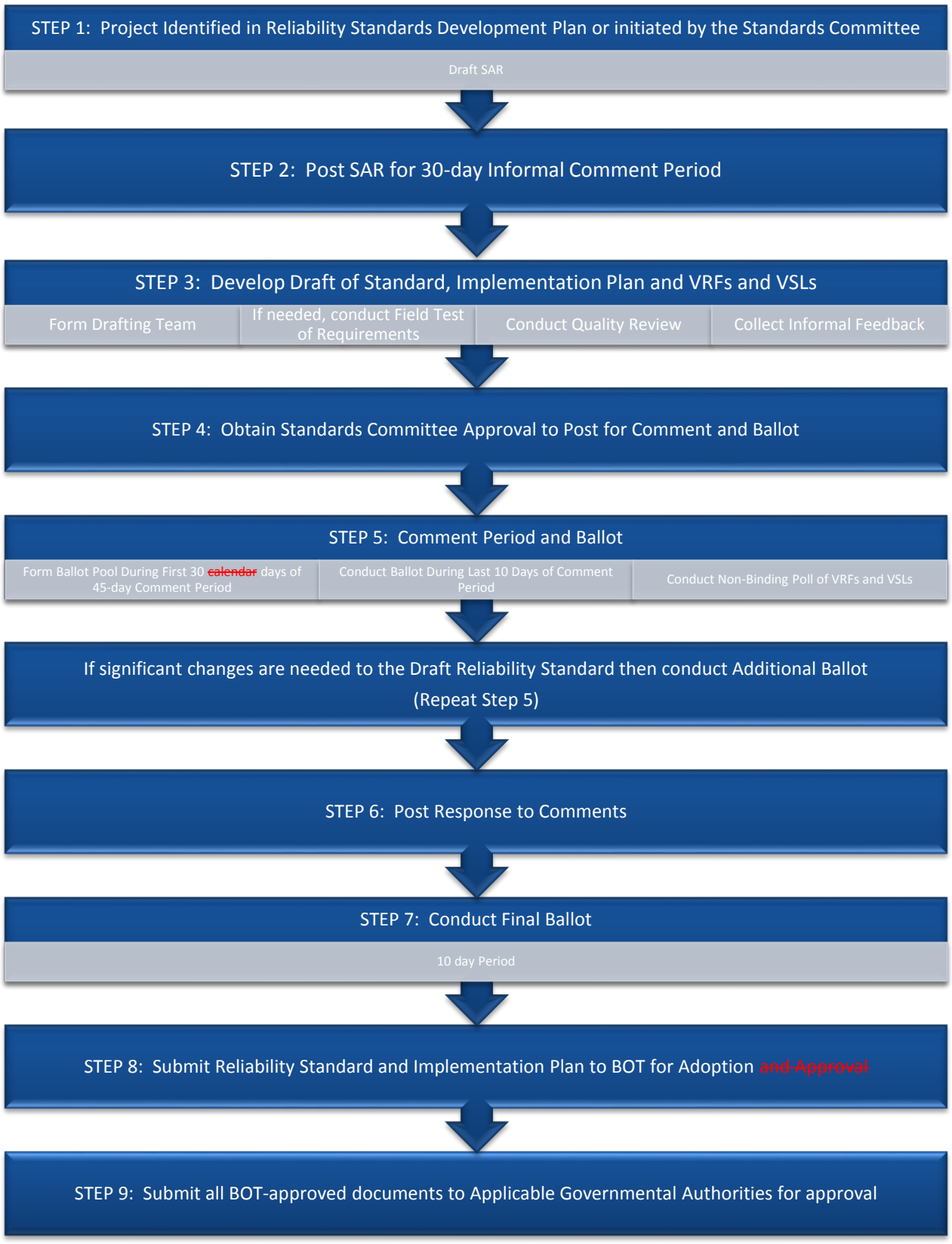


FIGURE 1: Process for Developing or Modifying a Reliability Standard

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.

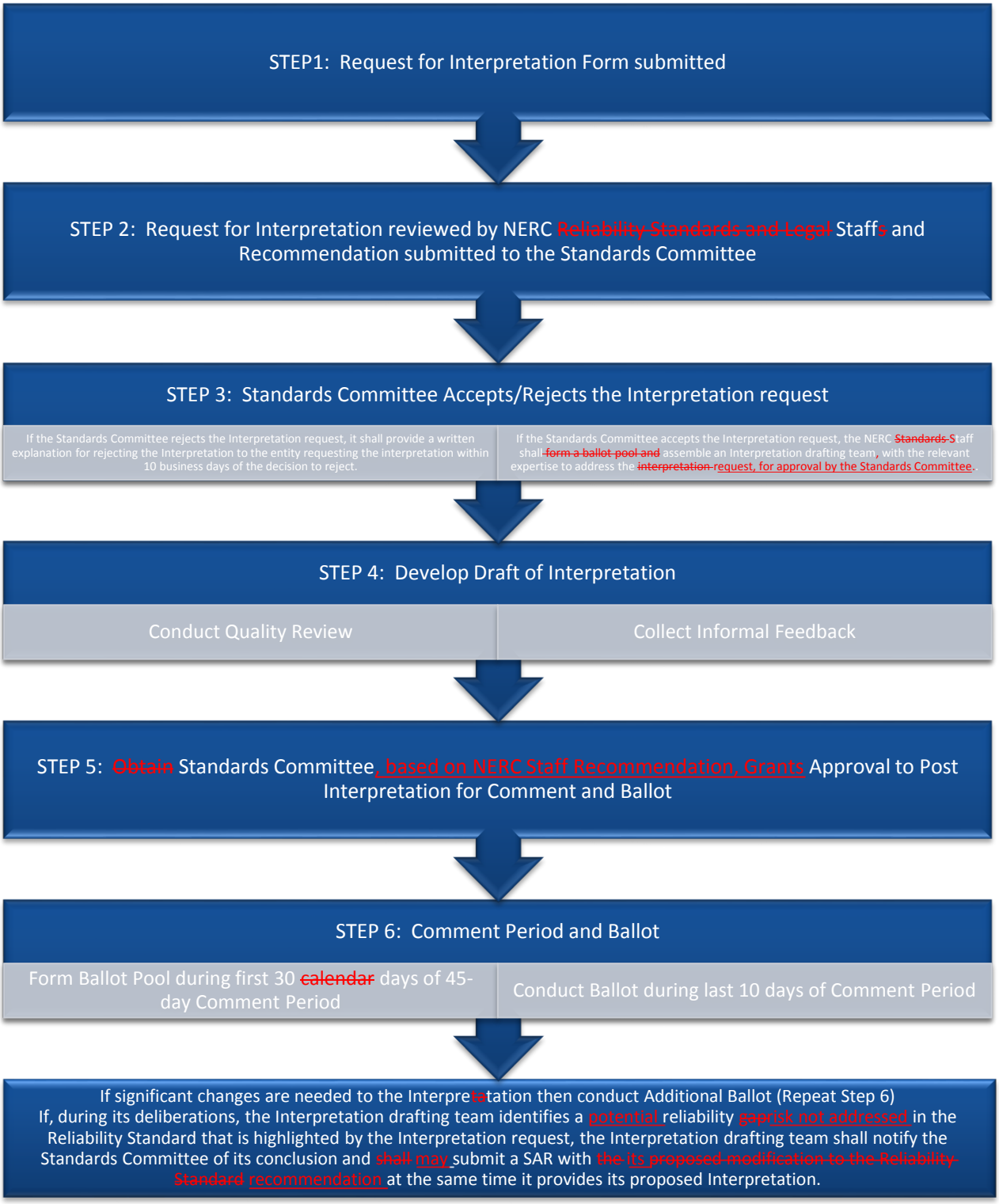
If, during its deliberations, the Interpretation drafting team identifies a potential reliability ~~gap~~ risk not addressed in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit 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.

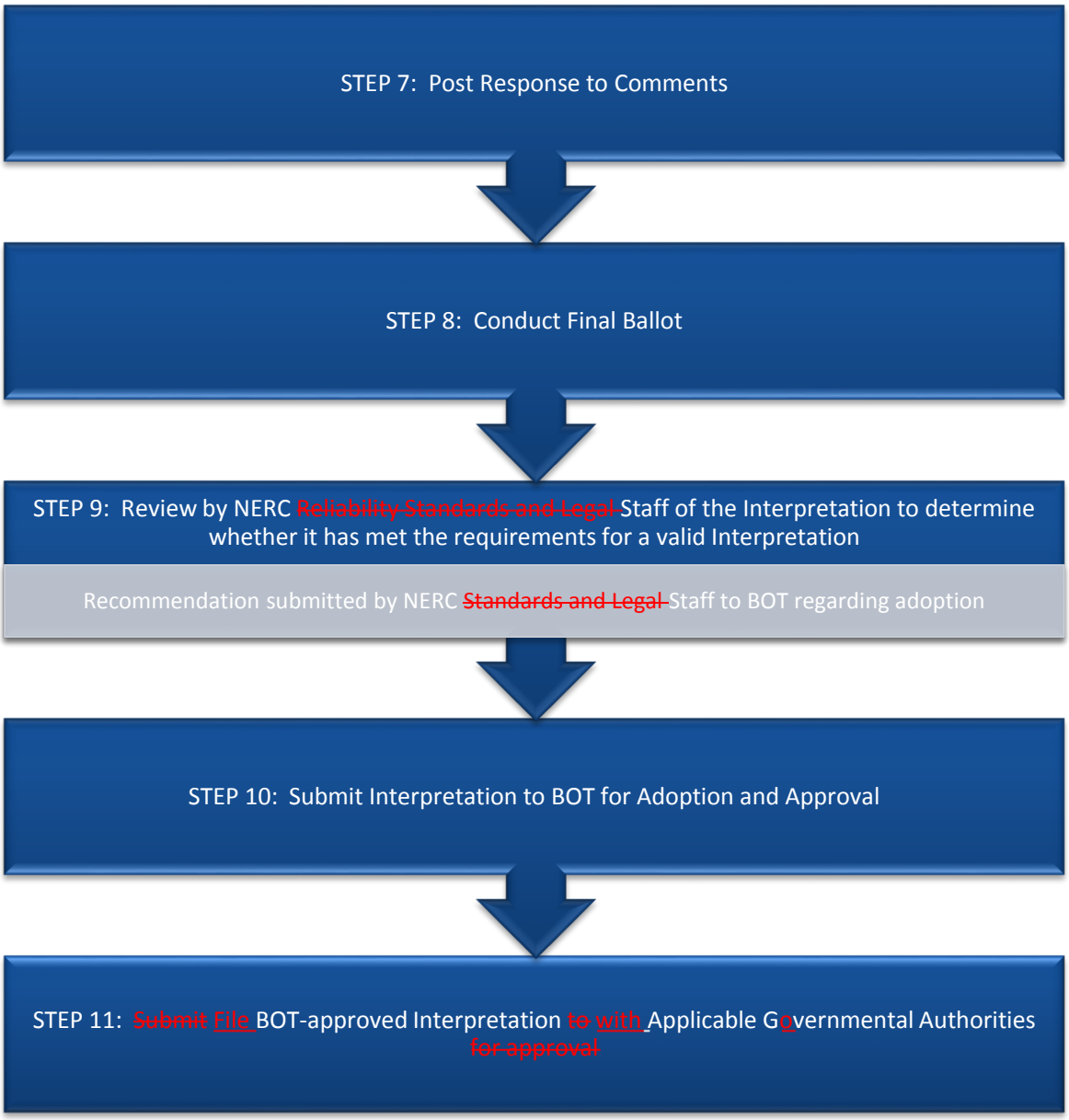


FIGURE 2: Process for Developing an Interpretation

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.

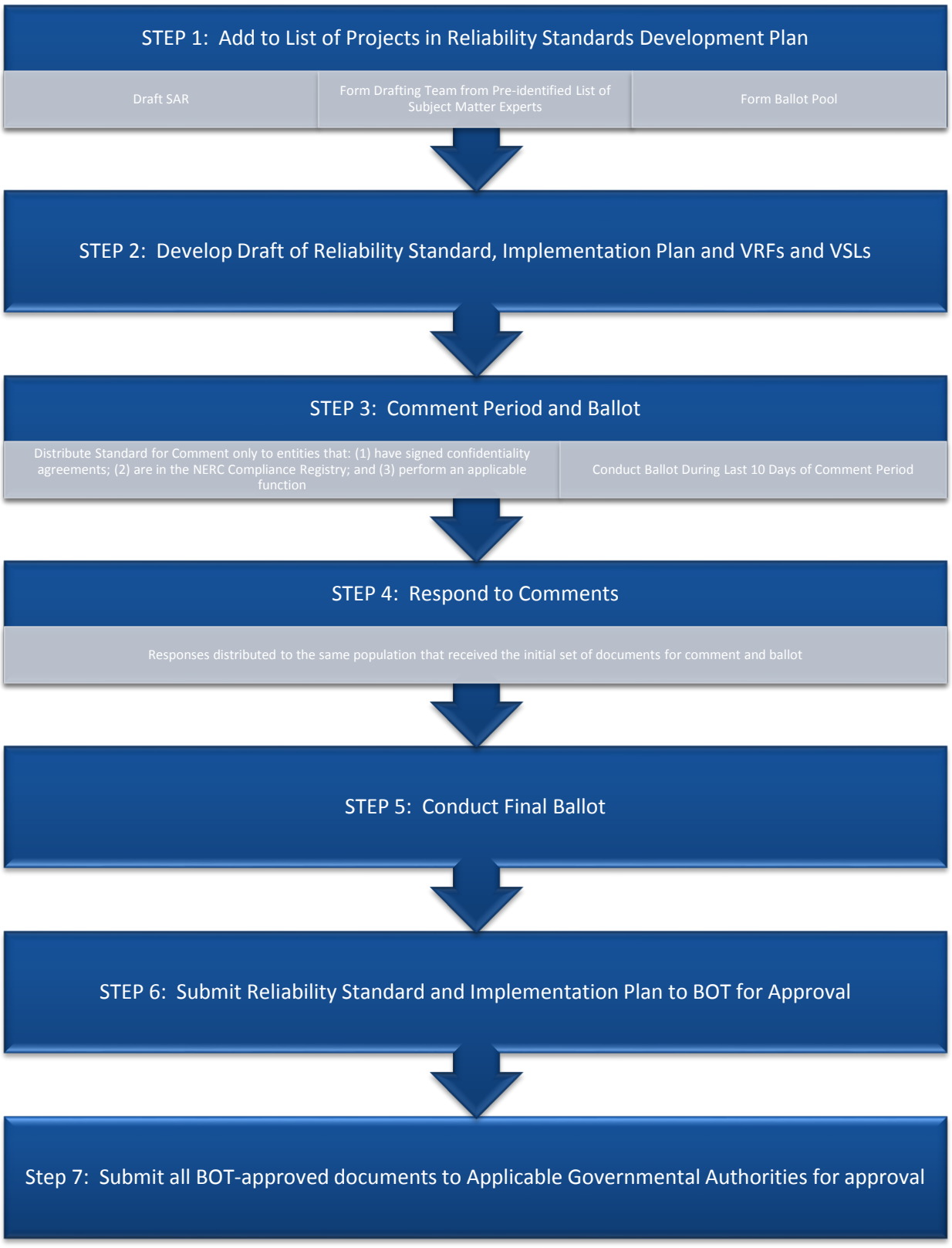


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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

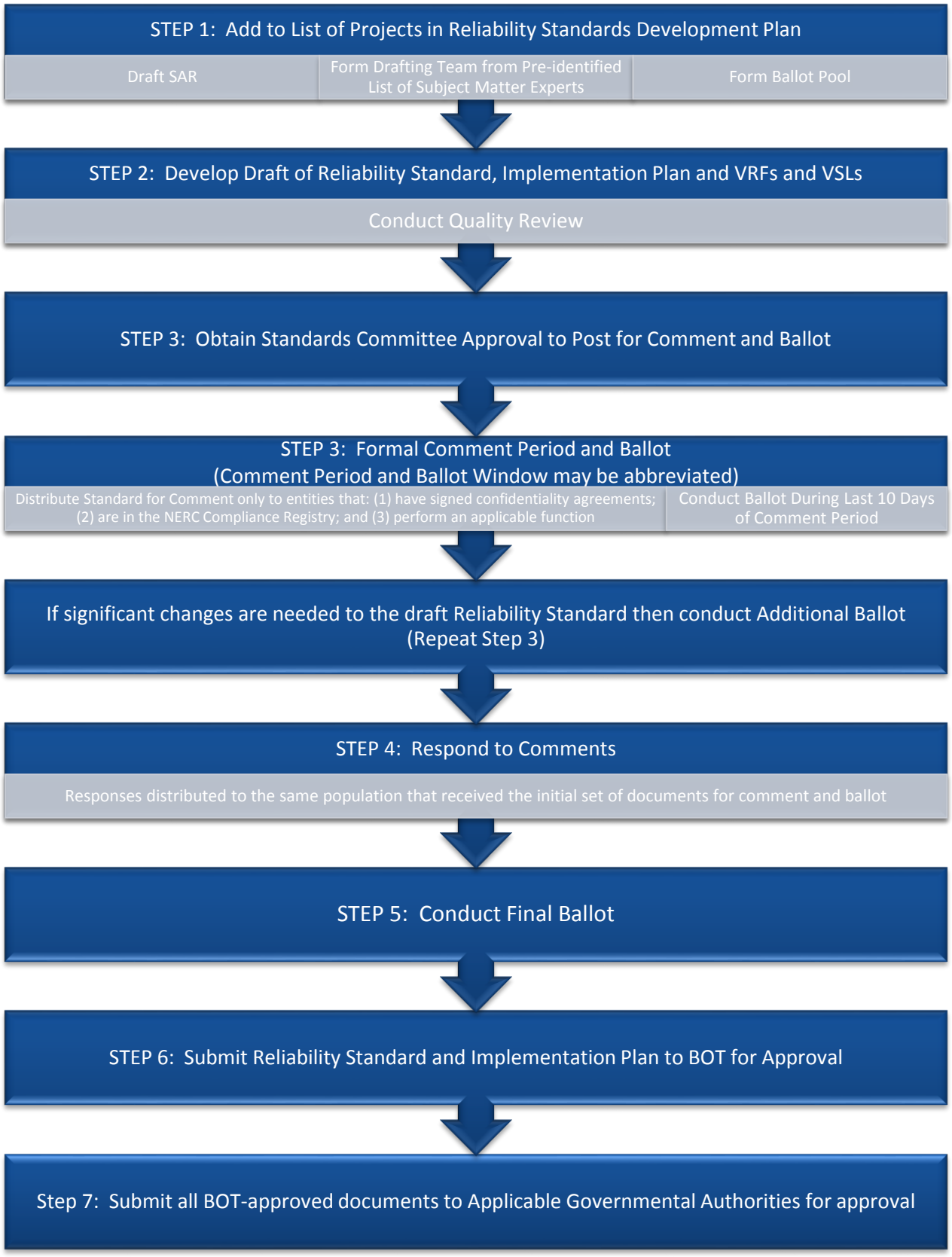


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

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.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION 4

Effective TBD

RELIABILITY | ACCOUNTABILITY

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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.

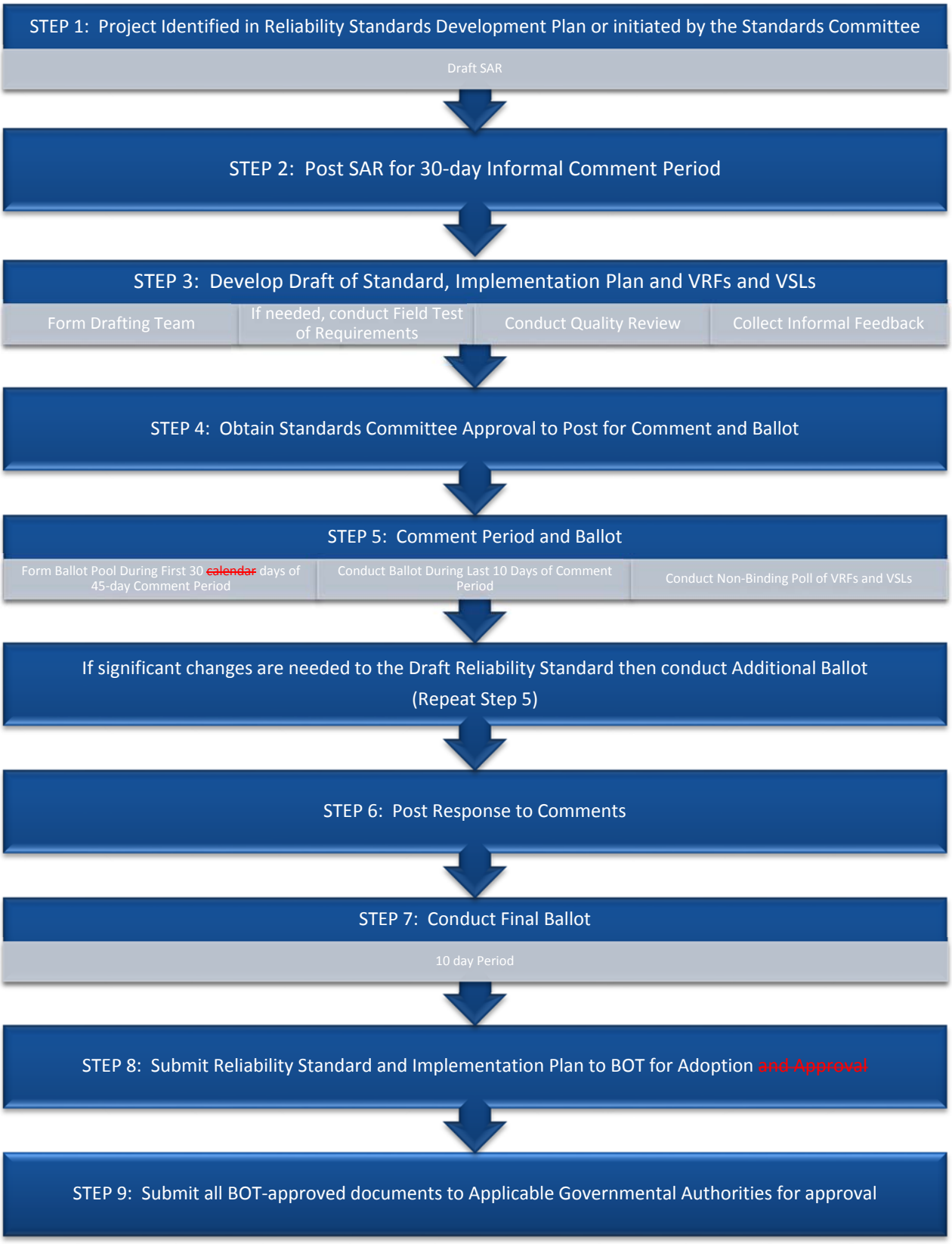


FIGURE 1: Process for Developing or Modifying a Reliability Standard

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.

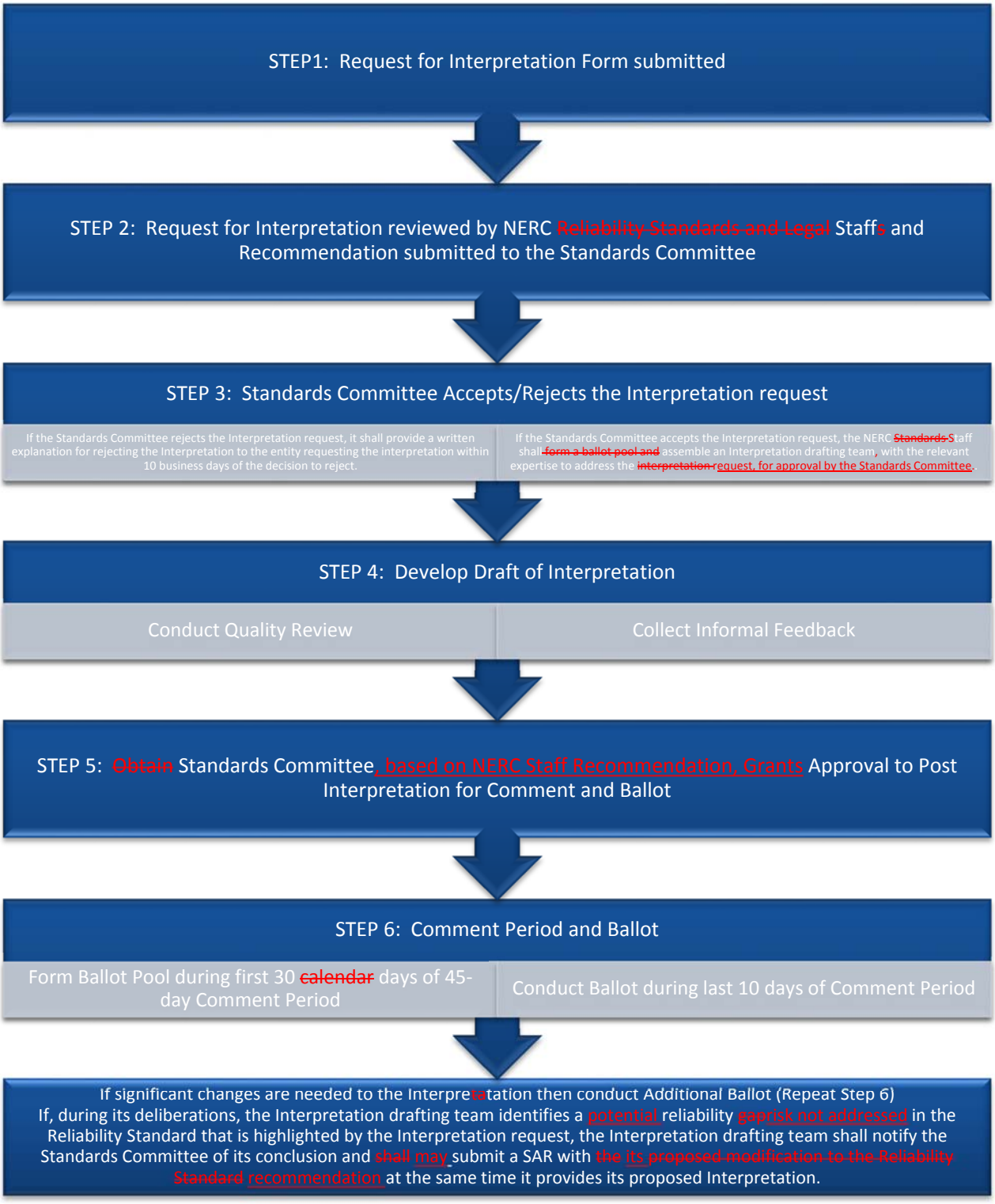
If, during its deliberations, the Interpretation drafting team identifies a potential reliability ~~related deficiency~~ risk not addressed in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion 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.

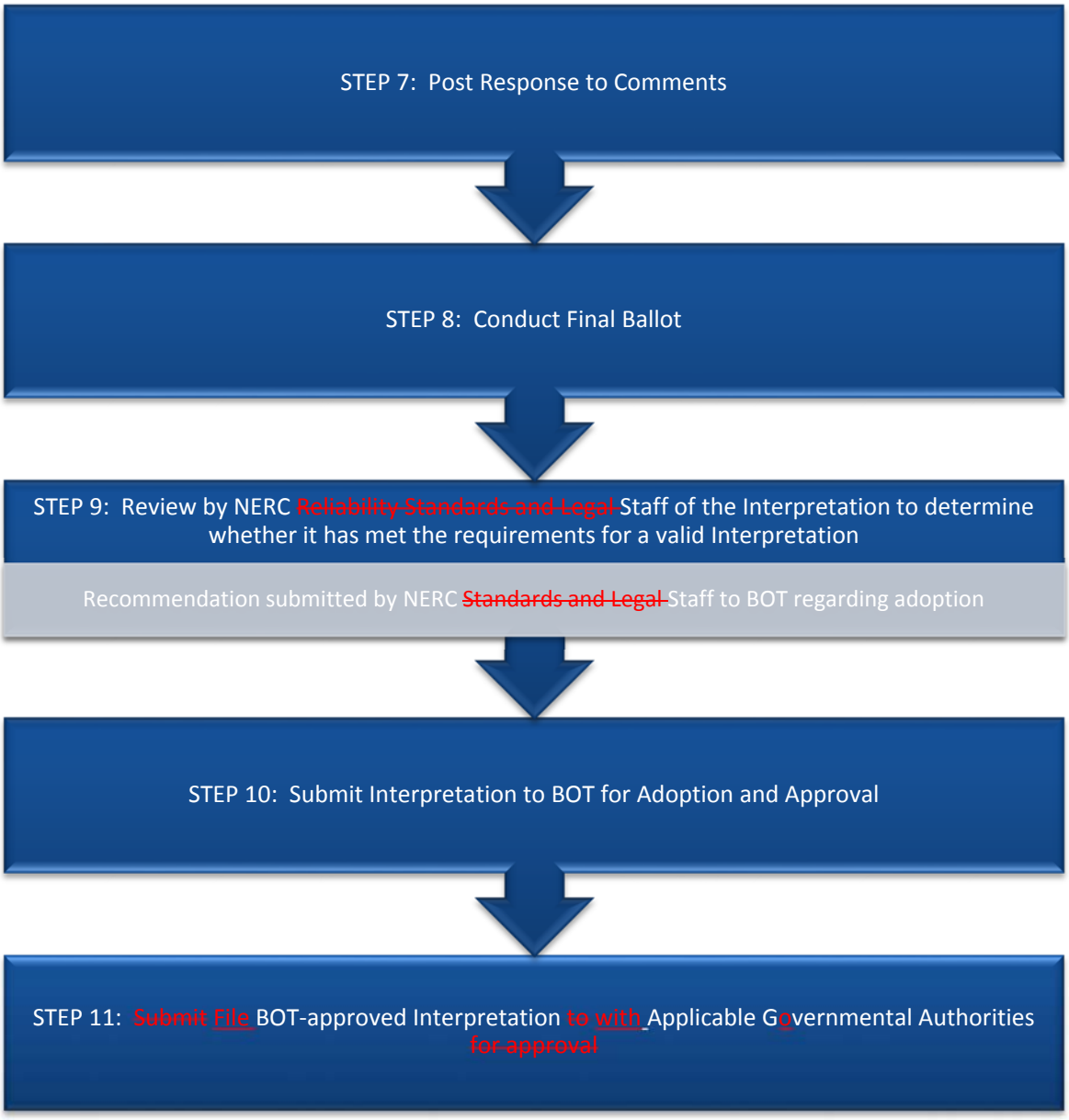


FIGURE 2: Process for Developing an Interpretation

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.

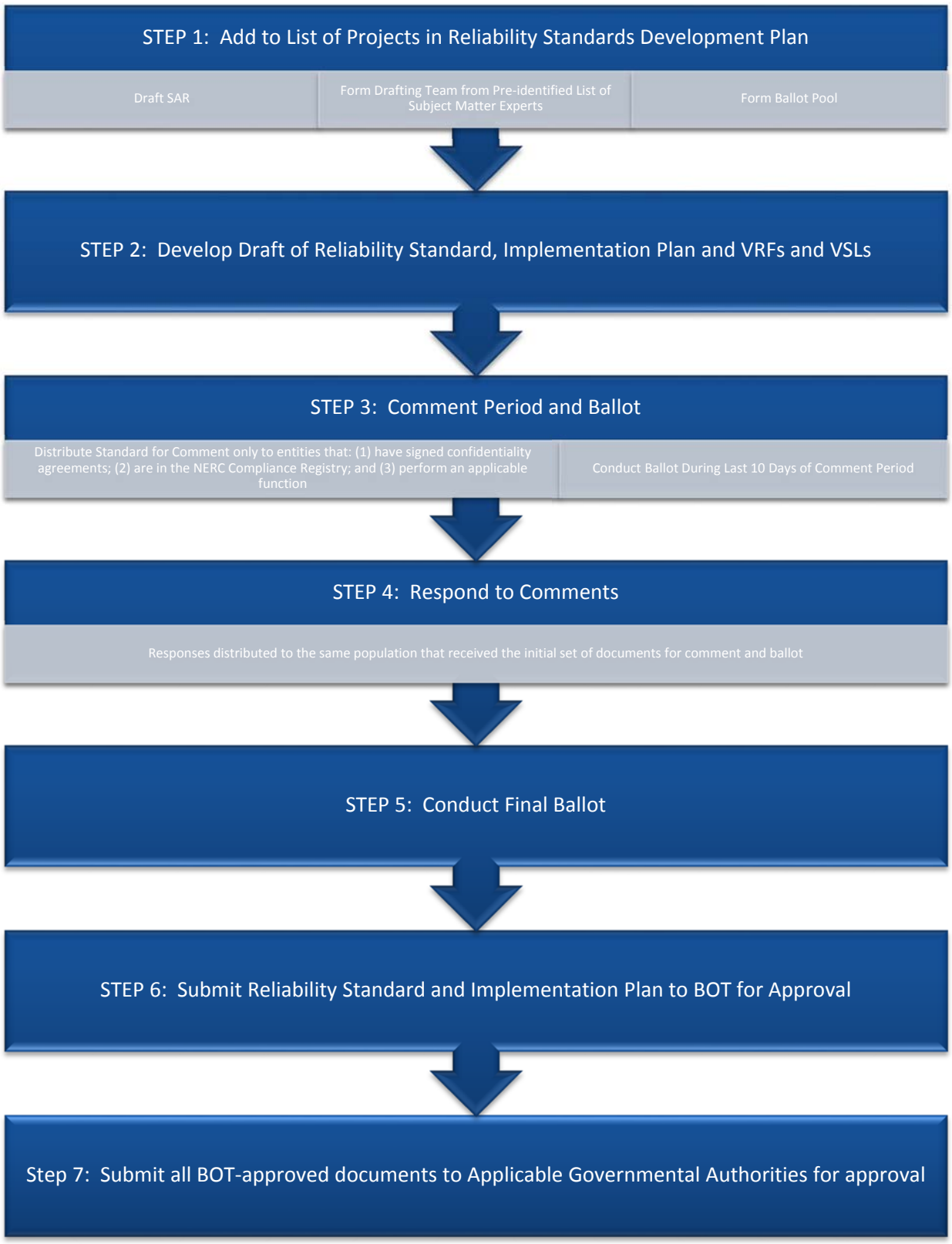


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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

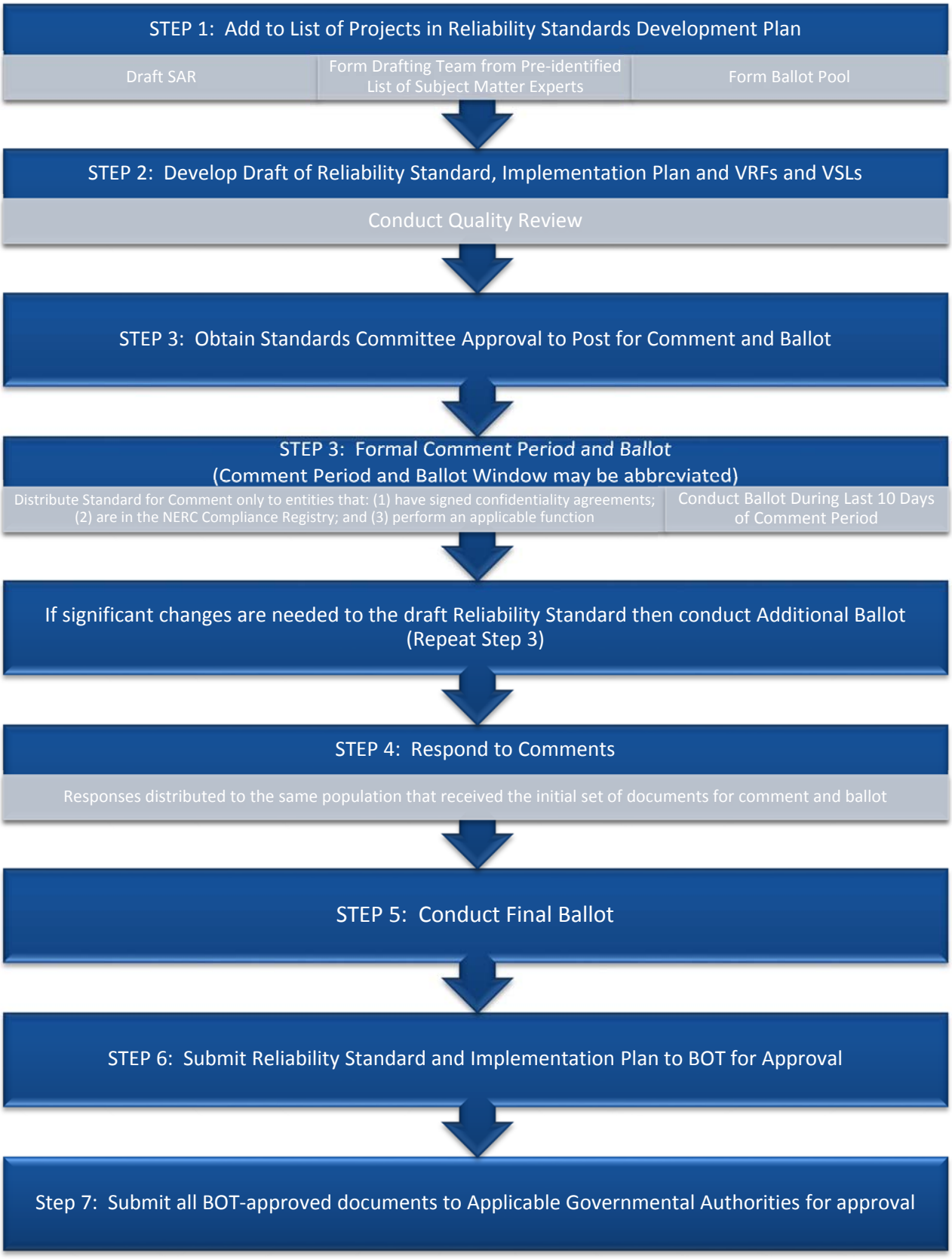


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

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.~~

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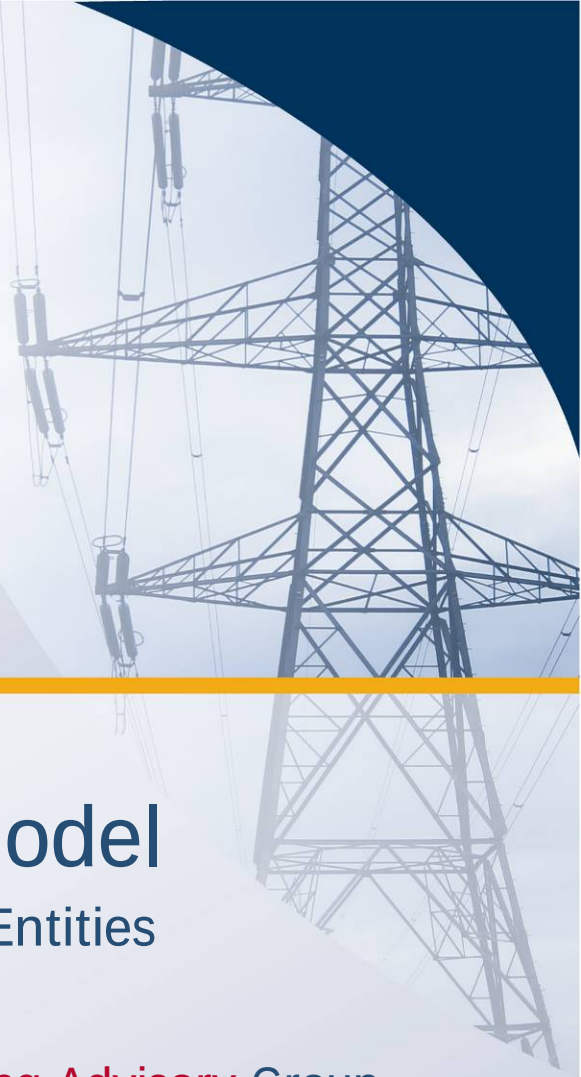

Reliability Functional Model

Function Definitions and Functional Entities

Version 5.1

Prepared by the Functional Model ~~Working~~ Advisory Group

~~Approved~~ Endorsed by Standing Committees: ~~December 2009~~
~~Approved~~ Endorsed by Standards Committee: ~~January 2010~~
~~Approved by Board of Trustees: May 2010~~

to ensure the reliability of the bulk power system

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Revision Summary

The Version 5.1 is an update of the Reliability Functional Model ("the Model" or "Functional Model") that includes the following changes from Version 45:

- ~~Performed detailed analysis on the Planning functions (Planning Reliability, Transmission Planning and Resource Planning) and entities (Planning Coordinator, Transmission Planner and Resource Planner). Clarifying revisions were made to these entities, in particular with respect to the Resource Planning function.~~
- ~~Interchange Authority has been changed to Interchange Coordinator. This version also incorporated the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.~~
- Terminology
- ~~Clarified asset ownership and maintenance for Generator Owner/Operator and Transmission Owner/Operator.~~
- Errata changes made as necessary.

Terminology Changes

Version 5.1 contains terminology changes intended to improve consistency between the Model and the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary" or "Glossary")~~NERC Glossary~~, the Rules of Procedure (ROP) and Reliability Standards. Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of two~~hree~~ types:

- The terms and definitions in this version of the Functional Model have been aligned with the Glossary[1].
- The Model has been revised regarding terms that are capitalized in the Glossary[2].
- ~~Functional Entity terminology~~
- ~~Entity names~~
- ~~Functional Entity definitions~~

~~Entity terminology~~

~~The Model has been revised regarding terms that are capitalized in the Glossary. In some situations a term was not capitalized per the Glossary. A footnote has been added to give the~~

[1] A table giving current definitions in the Model and Glossary and the proposed definitions is given in the Technical Document.

[2] Unless otherwise indicated, all capitalized terms shall have the meaning set forth in the Glossary or in the Model. In several places in this document, certain Glossary-defined terms are not capitalized as they are intended to have their ordinary meanings (e.g., load) or are intended to match the capitalization of terms within Glossary definitions.

rationale for keeping the term lower case.The term "responsible entity" in the Model has been changed to "functional entity". 3

- The usage of "responsible" in Version 4 derives from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" with "functional" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the ROP and Glossary to consistently use the term "functional entity" when the reference is to the *class of entity* (e.g., BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[4]
-

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the entity.
  - A conforming change is required in the Glossary
  - Conforming changes are required in other NERC documents.

Functional Entity Names have been revised to the same wording as in the Glossary.

Functional Entity definitions

- The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.
- The Ffunctional Eentity definitions have been aligned to the same wording as in the Glossaryrevised[5].
  - The form of the definitions is uniform, with each definition beginning: "The functional entity that…".
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

[3] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", i.e., all lower case, this usage has been adopted for version 5 of the Model.
[4] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.
[5] A table giving current definitions in the Model and Glossary and the proposed definitions is given in the Technical Document.

Foreword

This document replaces version 54 of the NERC Reliability Functional Model that the NERC Board of Trustees ~~Standing Committees~~ approved in May 2010~~September 2009~~8.

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the F~~f~~unction of ~~Transmission Service Provider~~ Transmission Service through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability F~~f~~unction to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation,
2. Some states and provinces were instituting "customer choice" options for selecting energy providers, and
3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The ~~task force~~ CACTF began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called "functions." Ultimately, the ~~Task Force~~ CACTF decided to build a "Functional Model". This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability — whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on — can identify those functions they perform, and register with NERC as one or more of the ~~f~~Functional ~~e~~Entities. Initially the Model dealt with operating functions, but it was subsequently expanded in ~~V~~version 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards

drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.

Adapted from Version 2 of the NERC Functional Model, February 10, 2004

Introduction

The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:

- The Model describes a set of ~~Functions~~ tasks that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability ~~T~~tasks. The Model assigns each Function to a F~~f~~unctional E~~e~~ntity, that is, the entity that performs the F~~f~~unction. The Model also describes the interrelationships between that ~~f~~Functional E~~e~~ntity and other functional entities (that perform other Functions).
- NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a F~~f~~unctional E~~e~~ntity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a ~~T~~task within a Function. A standard requirement will be very specific, whereas a ~~T~~task in the Model will be more general in nature.
- NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model ~~it~~ is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure.

An organization may perform more than one Function.

The Functional Model describes a F~~f~~unctional E~~e~~ntity envisioned to ensure that all of the ~~T~~tasks related to its Function are performed. The Model, while using the term "F~~f~~unctional E~~e~~ntity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a F~~f~~unctional E~~e~~ntity is "legally responsible" for meeting the standards requirements assigned to that F~~f~~unctional E~~e~~ntity.

The work performed to meet the requirements may be self-~~-~~performed or performed by others.

Functional Model maintenance. The Functional Model is maintained by the Functional Model ~~Working~~ Advisory Group (~~FMWG~~FMAG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC)

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.

Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the ~~T~~tasks within a Function.

Function. A set of related reliability ~~T~~tasks.

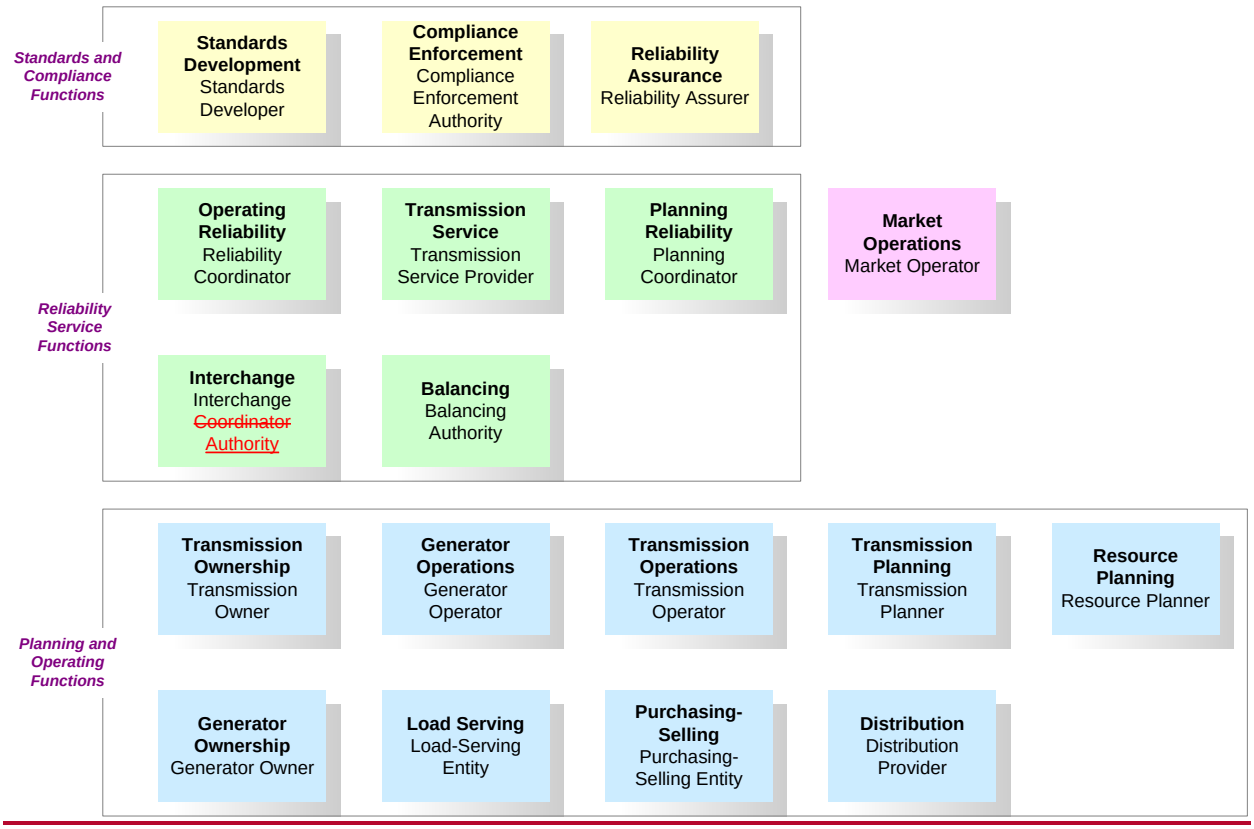
~~Task. One of the elements that make up a Function in the Functional Model.~~

~~**Customer**. The term applies to a customer for transmission, capacity or energy services (a Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).~~

End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

Functional Model Diagram

Function Name	***Functional Entity***
Balancing	Balancing Authority
Compliance Enforcement	Compliance Enforcement Authority
Distribution	Distribution Provider
Generator Operations	Generator Operator
Generator Ownership	Generator Owner
Interchange	Interchange ~~Coordinato~~Authorityr
Load-Serving	Load-Serving Entity
Market Operations	Market Operator (Resource Integrator)
Operating Reliability	Reliability Coordinator
Planning Reliability	Planning Coordinator
Purchasing-Selling	Purchasing-Selling Entity
Reliability Assurance	Reliability Assurer
Resource Planning	Resource Planner
Standards Development	Standards Developer
Transmission Operations	Transmission Operator
Transmission Ownership	Transmission Owner
Transmission Planning	Transmission Planner
Transmission Service	Transmission Service Provider


Standards and Compliance Functions
Standards Development
Standards Developer
Compliance Enforcement
Compliance Enforcement Authority
Reliability Assurance
Reliability Assurer
Reliability Service Functions
Operating Reliability
Reliability Coordinator
Transmission Service
Transmission Service Provider
Planning Reliability
Planning Coordinator
Market Operations
Market Operator
Interchange
Interchange Coordinator Authority
Balancing
Balancing Authority
Planning and Operating Functions
Transmission Ownership
Transmission Owner
Generator Operations
Generator Operator
Transmission Operations
Transmission Operator
Transmission Planning
Transmission Planner
Resource Planning
Resource Planner
Generator Ownership
Generator Owner
Load Serving
Load-Serving Entity
Purchasing-Selling
Purchasing-Selling Entity
Distribution
Distribution Provider

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain ~~T~~tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the ~~T~~tasks within the Functions. The framework for developing the Function definitions is:
    a. The Functions are independent of the organization structure performing the functions, and
    b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.

Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's ~~T~~tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these ~~T~~tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

1. The Model must be *complete*, that is, it must include all reliability ~~T~~tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a ~~T~~task in the Model and therefore be assignable to a particular F~~f~~unctional E~~e~~ntity.
2. The Model must group these ~~T~~tasks into a set of Functions, such that:
   - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and
   - The number of Functions is developed based on logical grouping of the ~~T~~tasks and kept low as reasonably possible.
     - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new F~~f~~unctional E~~e~~ntity. That is, the fundamental reliability ~~T~~tasks, and hence the Function, remain the same - all that has changed is *how* the Function is performed. ~~Examples of such groups are a rReserve sSharing gGroup (a collection of entities that are Balancing Authorities), or a planned resource sharing group.~~
3. The Model is structured to ensure there are no gaps or overlaps in the performance of operation ~~T~~tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each F~~f~~unctional E~~e~~ntity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.
4. Tasks describe *what* is to be done, not *how* it is to be done.
5. The Model is a guideline that describes reliability ~~T~~tasks and interrelationships between the entities that perform them - it is not prescriptive. In particular, the Model does not

address requirements for registering or becoming certified as a Ff~~f~~unctional Ee~~e~~ntity, or the delegation or splitting of responsibility for meeting standards requirements.

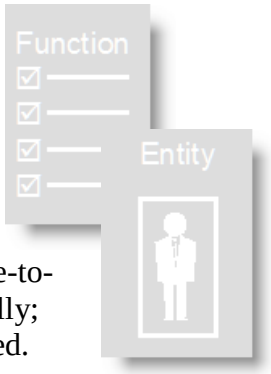
Functional Model — Clarification Service

The Functional Model is a reference tool that links ~~f~~Functional ~~e~~Entities with associated reliability-related functions and respective ~~T~~tasks. Drafting teams use the Functional Model to help them determine which F~~f~~unctional E~~e~~ntity should be required to comply with each requirement in a ~~r~~Reliability ~~s~~Standard.

From time to time questions of clarification and interpretation arise. The FMA~~W~~G is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding ~~T~~tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMA~~W~~G facilitator with a request for clarification.

1. The NERC Staff assigned as the FMA~~W~~G facilitator will convene a conference call/meeting of available members of the FMA~~W~~G to review the question(s) and provide a clarification.
   - If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMA~~W~~G and available members of the drafting team to discuss the issues in more detail.
2. Each FMA~~W~~G request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.
   - If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.

Functions and Functional Entities



This section defines the functions and associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also characterizes the functional entities that perform these ~~T~~tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove ~~T~~tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where a one-to-one relationship exists, the Model will include the reciprocal relationship specifically; and where a one-to-many relationship exists, the reciprocal relationships are implied.

Function — Standards Development

Tasks

1. Develop and maintain a standards development process.
2. Develop Reliability Standards for the planning and operation of the Bulk Electric System.

Functional Entity — Standards Developer

Definition
The ~~f~~Functional ~~e~~Entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.

Introduction to the Standards Developer
The Model addresses Reliability Standards created at NERC using the NERC Standard Processes Manual~~NERC Reliability Standards Development Procedure~~ and Regional Reliability Standards~~Regional Standards~~ that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.

Relationships with Other Functional Entities

1. Receives request for Reliability Standards through the public process.
2. Sends Reliability Standards to the Compliance Enforcement Authority.

Function — Compliance Enforcement

Tasks

1. Develop, maintain and implement a compliance enforcement process.
2. Evaluate and document compliance.

Functional Entity — Compliance Enforcement Authority

Definition

NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards~~.

Relationships with Other Functional Entities

1. Receives Reliability Standards from the Standards Developer.
2. Administers the compliance enforcement process for all functional entities as required by Reliability Standards.

Function — Reliability Assurance

Tasks

1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.
2. Coordinate the activities related to maintaining critical infrastructure protection.
3. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.
4. Identify and address gaps in reliability processes and responsibilities.

Functional Entity — Reliability Assurer

Definition

The ~~f~~Functional ~~e~~Entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.

Relationships with Other Functional Entities

1. Coordinates reliability assurance activities of the F~~f~~unctional E~~e~~ntities within the Reliability Assurer area.
2. Coordinates reliability assurance activities with adjacent Reliability Assurers.
3. Coordinates critical infrastructure protection programs with F~~f~~unctional E~~e~~ntities.
4. Collects information from ~~f~~Functional ~~e~~Entities related to Reliability Assurance processes.

Function — Planning Reliability

Tasks

1. Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.
2. Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:
    a. Transmission facility characteristics and ratings.
    b. Demand and energy forecasts, capacity resources, and demand response programs.
    c. Generator unit performance characteristics and capabilities.
    d. Long-term capacity purchases and sales.
3. Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.
    a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.
    b. Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
    c. Review and determine transfer capability (generally one year and beyond) as appropriate.
    d. Monitor and evaluate transmission expansion plan and resource plan implementation.
    e. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
4. Coordinate with adjoining Planning Coordinators so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.
5. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

Functional Entity — Planning Coordinator

Definition

The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and Protection Systems.[6] ~~The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one S~~s~~ystem does can affect the other ~~s~~Systems. Planning Coordinators work through a variety of mechanisms to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all network areas with little or no ties to others' areas, such as interconnections, are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.
2. Coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators.
3. Coordinates plans with Reliability Coordinator and other Planning Coordinators on reliability issues.
4. Receives plans from Transmission Planners and Resource Planners.
5. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term capacity purchases and sales from Transmission Service Providers.

[6] In the NERC Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

6. Collects and reviews reports on ~~t~~Transmission and resource plan implementation from Resource Planners and Transmission Planners.
7. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.
8. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the ~~transmission~~ S~~s~~ystem.
9. Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.
    a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining ~~s~~Systems.
    b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.

Function — Transmission Planning

Tasks

1. Maintain and develop, in cooperation with adjacent and overlapping Transmission Planners, methodologies and tools for the analysis and simulation of the ~~t~~Transmission systems in the evaluation and development of ~~t~~Transmission expansion plans related to resource ~~a~~Adequacy plans.
2. Define, consolidate and collect or develop, in cooperation with adjacent and overlapping Transmission Planners, information required for planning purposes including:
   a. Transmission facility characteristics and ~~r~~Ratings.
   b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs.
   c. Generator unit performance characteristics and capabilities.
   d. Long-term capacity purchases and sales
3. Maintain transmission system models (steady state, dynamics, and short circuit) to evaluate Bulk Electric System performance.
4. Coordinate with adjacent and overlapping Transmission Planners so that system models and resource and ~~t~~Transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas.
5. Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements.
   a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for ~~t~~Transmission ~~s~~Service.
   b. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) ~~f~~Facilities into the Bulk Electric System.
   c. Determine ~~t~~Transfer ~~c~~Capability values (generally one year and beyond) as appropriate.
   d. Monitor, evaluate and report on ~~t~~Transmission expansion plan and resource plan implementation.
   e. Coordinate projects requiring ~~t~~Transmission outages that can impact reliability and firm ~~t~~Transactions.
6. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned ~~t~~Transmission changes that may impact their ~~f~~Facilities.
7. Define system protection and control needs and requirements, including ~~s~~Special ~~p~~Protection ~~s~~Systems (~~r~~Remedial ~~a~~Action ~~s~~Schemes), to meet reliability needs.

Functional Entity — Transmission Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority~~a Transmission Planner~~ area.

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the longer-term (generally one year and beyond) reliability of its Transmission Planner area. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas and overlap one or more adjacent Transmission Planners.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, other Transmission Planners, Transmission Owners, and Transmission Service Providers.
2. Collects information including:
   a. Transmission facility characteristics and ~~r~~Ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
   b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs from Load-Serving Entities, and Resource Planners.
   c. Generator unit performance characteristics and capabilities from Generator Owners.
   d. Long-term transmission capacity purchases and sales from Transmission Service Providers
3. Informs Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the ~~t~~Transmission system.
4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.
5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.
6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

7. Notifies other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted of any planned Bulk Electric System changes.
8. Coordinates with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
9. Submits and coordinates the plans for the interconnection of Ff~~f~~acilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and Resource Planners, as appropriate.
10. Coordinates and develops ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners and Transmission Service Providers
11. Coordinates with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~s~~Special ~~p~~Protection ~~s~~Systems (~~r~~Remedial ~~a~~Action ~~s~~Schemes), to meet reliability needs.
12. Receives maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of Bulk Electric System expansion plans.

Function — Resource Planning

Tasks

1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy.~~.~~
2. Monitor and report, as appropriate, on its resource plan implementation.
3. Develop and maintain resource (demand and capacity) models to evaluate resource adequacy.
4. Collect or develop information required for resource adequacy purposes, including:
   a. demand and energy forecasts, capacity resources, and demand response programs,
   b. generator unit performance characteristics and capabilities, and
   c. long-term capacity purchases and sales and
   d. transmission (interface) limits.
5. Evaluate, develop, document, and report on a resource adequacy plan for its portion of the Transmission Planner and Planning Coordinator area.
6. Assist in the evaluation of the deliverability of resources.

Functional Entity — Resource Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a ~~Resource Planner~~Planning Authority area.

Relationships with Other Functional Entities

1. Coordinates the resource models with its Planning Coordinator.
2. Coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to Transmission C~~c~~ustomers.
3. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Planners, Transmission Operators, Interchange ~~Coordinator~~Authority(ies), and Reliability Assurers.
4. Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans.
5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.
6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.
7. Reports on resource plan implementation to the Transmission Planner, Planning Coordinator and Reliability Assurer.
8. Works with the Planning Coordinator and Transmission Planners to identify potential alternative transmission solutions to meet Resource Planner plans.
9. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.

Function — Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and generation/Ttransmission maintenance plans.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining reliability-related services requirements for balancing generation and load, and Ttransmission reliability (e.g., reactive requirements, location of operating reserves).
5. Perform reliability analysis (actual and contingency) for the reliability area.
6. Direct revisions to Ttransmission maintenance plans as permitted by Aagreements.
7. Direct revisions to generation maintenance plans as permitted by Aagreements.
8. Direct implementation of emergency procedures including load shedding.
9. Direct and coordinate system restoration.
10. Curtail Confirmed Interchange that adversely impacts reliability.

Functional Entity — Reliability Coordinator

Definition

The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area~~.

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's W~~w~~ide~~-~~ A~~a~~rea view. The ~~w~~Wide~~-~~ ~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

Transmission operations. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its own defined area. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a "W~~w~~ide~~-~~ A~~a~~rea" view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this "W~~w~~ide~~-~~ A~~a~~rea" view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

Balancing operations. The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on T~~t~~ransmission ~~system~~ limitations.

2. Receives ~~f~~Facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives T~~t~~ransmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans and reliability-related services.

Real Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange ~~Coordinator~~Authority(ies) and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange ~~Coordinator~~Authority(ies), Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange ~~Coordinator~~Authority(ies).
19. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.

21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.
24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Function — Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
   a. lLoad and generation (an isolated system)
   b. lLoad and Confirmed Interchange
   c. gGeneration and Confirmed Interchange
   d. gGeneration, load, and Confirmed Interchange
2. Calculate Aarea Ceontrol Eerror within the reliability area.
3. Operate in the Balancing Authority Area to maintain load-interchange-generation balance.
4. Review generation commitments, dispatch, and load forecasts.
5. Formulate an operational plan (generation commitment, outages, etc.) for reliability evaluation.
6. Approve Arranged Interchange from ramping ability perspective.
7. Implement Confirmed Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Interchange, Implemented Interchange and actual interchange), and administer inadvertent energy paybacks.
11. Determine needs for reliability-related services.
12. Deploy reliability-related services.
13. Implement emergency procedures.

Functional Entity — Balancing Authority

Definition

The responsible ~~functional~~ entity that integrates resource plans ahead of time, maintains ~~generation~~ load-interchange-generation balance within a Balancing Authority Area, and ~~contributes to~~supports Interconnection frequency in real time.

Relationships with Other Functional Entities

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange ~~Coordinator~~Authority(ies).
5. Compiles load forecasts from Load-Serving Entities.
6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange ~~Coordinator~~Authority(ies).
9. Confirms Rr~~r~~amping capability with Interchange ~~Coordinator~~Authority(ies).
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators.

Real Time

17. Coordinates use of controllable loads with Load-Serving Entities (i.e., interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations).
18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange ~~Coordinator~~Authority(ies) of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in R~~r~~eal~~ ~~-time.
27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange Curtailments from Interchange ~~Coordinator~~Authority(ies).

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange ~~Coordinators~~ Authority(ies) after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout”.

Function — Market Operations

The Market Operations Function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with commercial functions.

Functional Entity — Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

Relationships with Other Functional Entities

Market Operator tasks and relationships are specific to a particular market design and will depend on the market structure over which the Market Operator presides.

Function — Transmission Operations

Tasks

1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities classed as transmission assets, which may include the transmission lines connecting a generating plant to the transmission system, associated protective relaying systems and Special Protection Systems.
3. Develop system limitations such as System Operating Limits and Total Transfer Capabilities, and operate within those limits.
4. Develop and implement emergency procedures.
5. Develop and implement system restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis (actual and contingency) for the Transmission Operator Area.
8. Adjust flow control devices within the transmission area to maintain reliability.
9. Deploy reactive resources to maintain transmission voltage within defined limits.

Functional Entity — Transmission Operator

Definition

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area~~.

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes. The Transmission Operator scope is narrower than the Reliability Coordinator, and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, the Transmission Operator can calculate System Operating Limits, but will not necessarily calculate Interconnection Reliability Operating Limits, which requires the wider scope of the Reliability Coordinator.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.

10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.
11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.
15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Function — Interchange

Tasks

1. Receive an Arranged Interchange.
2. Ensure an Arranged Interchange is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.).
3. Coordinate (i.e., collect and consolidate) approval, change, and denial requests for an Arranged Interchange to become Confirmed Interchange. Approvals may be explicit or by exception.
4. Receive confirmations of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (e.g., the interchange distribution calculator in the Eastern Interconnection).
7. Maintain record of an individual Confirmed Interchange.

Functional Entity — Interchange ~~Coordinator~~Authority

Definition

The ~~functional~~ responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas~~.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Arranged Interchange from Purchasing-Selling and Load Serving Entities.
2. Submits request for an Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receives approval or denial from Transmission Service Providers of transmission arrangement(s) for Arranged Interchange.
4. Receives approval or denial from Balancing Authorities of the ability to meet ramping requirements for submitted Arranged Interchange.
5. Communicates final approval or denial of a request for an Arranged Interchange to become Confirmed interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities and Load-Serving Entities for implementation and NERC identified reliability analysis services.

Real Time

6. Receives curtailments and redispatch implementation requests from Reliability Coordinators for an Arranged Interchange.
7. Receives information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, and Purchasing-Selling/Load-Serving Entities.
8. Informs Transmission Service Providers, Purchasing-Selling/Load-Serving Entities, Reliability Coordinators, and Balancing Authorities of Confirmed Interchange revisions (including curtailments).

After the hour

9. Maintains and provides a record of individual Confirmed Interchange for which it coordinated with the Balancing Authorities.

10. Coordinates Confirmed Interchange with Balancing Authorities after the hour for "checkout".

Function — Transmission Service

Tasks

1. Receive transmission service requests and process each request for service according to the requirements of the tariff.
   a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).
2. Determine and post Aavailable Ttransfer Ccapability values.
3. Approve or deny transmission service requests.
4. Approve Arranged Interchange from Ttransmission Sservice agreementtransmission service arrangement perspective.
5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.

Functional Entity — Transmission Service Provider

Definition

The ~~functional~~ entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~t~~Transmission ~~s~~Service agreements.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term Tt~~t~~ransmission ~~s~~Service requests.
4. Approves or denies Tt~~t~~ransmission St~~ransmission s~~ervice requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of Tt~~t~~ransmission St~~ransmission s~~ervice requests indicated in the Arranged Interchange with Interchange ~~Coordinator~~Authority(ies).
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).

Real Time

8. Receives Confirmed Interchange implementation (including curtailments) from the Interchange ~~Coordinator~~Authority(ies).
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authority(ies).

Function — Transmission Ownership

Tasks

1. Develop interconnection agreements.
2. Establish ratings of transmission facilities.
3. Maintain transmission facilities and rights-of-way.
4. Design and install owned facilities classified as transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of transmission protective relaying systems and Special Protection Systems.

Functional Entity — Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.

Relationships with Other Functional Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.
2. Receives approved transmission expansion plans from the Transmission Planner.
3. Develops agreements or procedures with the Transmission Service Providers.
4. Develops operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develops agreements with adjacent Transmission Owners for joint transmission facilities.
6. Provides transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provides transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provides maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.
10. Provides reactive resources to Transmission Operators.
11. Revises transmission maintenance plans as requested by the Reliability Coordinator.

Function — Distribution

Tasks

1. Provide and operate electrical delivery facilities between the transmission system and the End-use Customer.
2. Implement voltage reduction.
3. Design and maintain protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Special Protection Systems that interface with the transmission system.
4. Provide and implement load-shed capability.
5. Maintain voltage and power factor within specified limits at the interconnection point.

Functional Entity — Distribution Provider

Definition

Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer~~.

Introduction to the Distribution Provider

The Distribution Provider delivers Eelectrical Ee~~e~~nergy to the End-use Customer from the transmission system. For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. The Distribution Provider provides the switches and re-closers that could be used to shed load for emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with Transmission Planners on transmission expansion.
2. Coordinates system restoration plans with Transmission Operator.
3. Coordinates with End-use Customers and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provides operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.

Real Time

7. Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.
8. Implements system restoration plans as coordinated by the Transmission Operator.
9. Directs Load-Serving Entities to communicate requests for voluntary load curtailment.

Function — Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
3. Operate generators to provide ~~r~~Real Power and ~~r~~Reactive P~~p~~ower or Interconnected Operations Service~~reliability-related services~~ per contracts or arrangements.
4. Monitor the status of generating facilities.
5. Support Interconnection frequency.

Functional Entity — Generator Operator

Definition

The ~~functional~~ entity that operates generating Facility(ies)~~unit(s)~~ and performs the functions of supplying energy and reliability related services.

Relationships with Other Functional Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority.
2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related services.
3. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.
4. Reports status of automatic voltage or frequency regulating equipment to Transmission Operators.
5. Provides operational data to Reliability Coordinator.
6. Receives reliability analyses from Reliability Coordinator.
7. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
8. Receives reliability alerts from Reliability Coordinator.
9. Receives notification of transmission system problems from Transmission Operators.

Real Time

10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
11. Adjusts ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

Function — Generator Ownership

Tasks

1. Establish generating ~~f~~Facility ~~r~~Ratings, limits, and operating requirements.
2. Design and authorize maintenance of generation plant ~~protective relaying systems~~Protection Systems, Protection Systems on the transmission lines connecting the generation plant to the T~~t~~ransmission ~~s~~System, and Special Protection Systems.
3. Maintains owned generating~~-~~ facility.
4. Provide verified generating facility performance characteristics / data.

Functional Entity — Generator Owner

Definition

~~The functional e~~Entity that owns and maintains generating Facility(ies)~~units~~.

Relationships with Other Functional Entities

1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of ~~t~~Transmission- ~~s~~Service request from Transmission Service Provider.
5. Provides reliability related services to Purchasing-Selling Entity pursuant to an ~~a~~Agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Function — Purchasing-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required by tariffs.
3. Request implementation of Arranged Interchange.

Functional Entity — Purchasing-Selling Entity

Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities~~reliability related services~~.

Relationships with Other Functional Entities

Ahead of Time

1. Arranges for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
2. Submits Requests For Interchange to Interchange ~~Coordinator~~ Authority(ies).
3. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.
4. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).
5. Receives load profiles and forecasts from Load-Serving Entities.

Real Time

6. Notifies Interchange ~~Coordinator~~ Authority(ies) ~~-~~of Confirmed Interchange and Implemented Interchange cancellations or terminations.
7. Receives notice of Confirmed Interchange curtailments from Interchange ~~Coordinator~~Authority(ies).

Function — Load-Serving

Tasks

1. Collect individual load profiles.
2. Identify capability for and communicate requests for voluntary load curtailment.
3. Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of critical customer loads that are to be excluded from the load shedding systems.
4. Identify need for facilities and provide capability of self-provided reliability-related services for its load.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary ~~t~~Transmission ~~s~~Service, and reliability-related services.
7. Submits Requests For Interchange to Interchange ~~Coordinator.~~Authority(ies).
8. Manage resource portfolios to meet demand and energy requirements of End-use Customers.

Functional Entity — Load-Serving Entity

Definition

~~The functional entity that s~~Secures energy and ~~t~~Transmission ~~s~~Service (and related Interconnected Operations ~~reliability related s~~Services) to serve the electrical demand and energy requirements of its end~~-~~-use customers.

Relationships with Other Functional Entities

Ahead of Time

1. Submits load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinator, Resource Planners, and Transmission Planners.
2. Identifies new facility connection needs for End-use Customers.
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provides information as to self-provided reliability-related services to the Balancing Authority.
5. Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
6. Arranges for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
7. Submits Requests For Interchange to Interchange ~~Coordinator.~~Authority(ies).
8. Notifies Generator Operators if Arranged Interchange requests are approved or denied.
9. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).
10. Coordinates with Distribution Provider on identifying new facility interconnection needs.
11. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Real Time

12. Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
13. Communicate requests for voluntary load curtailment to E~~e~~nd-use C~~e~~ustomers as directed by the Balancing Authority and Distribution Provider.
14. Notifies Interchange ~~Coordinator~~Authority(ies) of Confirmed Interchange cancellations or terminations.
15. Receives notice of Confirmed Interchange curtailments from Interchange ~~Coordinator~~Authority(ies).

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Version 5.1

Prepared by the Functional Model ~~Working~~ Advisory Group

This document is a companion to Version 5.1 of the Functional Model. It provides context, explanations, opinions, and discussions on various aspects of the Functional Model.

~~Approved~~ Endorsed by Standing Committees~~Operating, Planning and Critical Infrastructure Protections Committees~~: ~~December 2009~~
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to ensure the reliability of the bulk power system

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Introduction

This document is intended as a companion to Version 5.1 of the Functional Model (Model) to help the reader better understand the Model's Functions, Ffunctional Eentities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5.1 of the Model.

Section I provides details about each of the ~~Responsible~~ Functional Entities. Some entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the ~~Functional~~ Model document, and there is little detail to add here. Others, such as the Interchange Coordinator Authority(ies) and Balancing Authority(ies), are more complex both unto themselves and in their relationship with other entities, and this document provides additional explanations.

Section II includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and Ffunctional Eentity boundary conditions. The discussion of Market Operations illustrates that the Model applies to different market structures.

Section I — Entity Tasks and Interrelationships

Version 4 of the Model, issued in 2008, clarified the concept of *responsibility* in the Model, as reflected in the use of the term Responsible Entity. In particular, it was clarified that while there were responsibilities of the entities in the FunctionFunctional Model *within the context of the Model itself,* the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance processes and Reliability Standards, not by the Model.

However, it subsequently became apparent to the FunctionFunctional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 55.1 goes one step further and eliminates reference to *responsibility* within the Model, replacing the term *responsible entity* with the term *functionFunctional Eentity*. In Version 55.1 of the Model, an entity is defined by the Ffunctions it performs.[1]

As a result of refocusing the Model on TaskTasks rather than responsibility, Version 55.1 of the Technical Document has removed discussions associated with responsibility of individual organizations. These matters are now addressed within the context of NERC's registration and compliance programs, typically within NERC's Rules of Procedure. These include situations where:

- an organizations may "bundle" a number of different functionFunctions and register as the corresponding functionFunctional entities, for example Reliability Coordinator and Transmission Operator
- two or more organizations may register jointly with NERC as functionFunctional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)
- an organization may register and assume responsibility for TaskTasks performed by others, such as a rural cooperative on behalf of its members.

[1] Version 5 of the Model uses the term "functionFunctional entityFunctional Entity" to apply to the *entity described in the FunctionFunctional Model* (Balancing Authority, etc.). It is proposed that other NERC documents follow this usage, and also that they use the terms "registered entity", "certified entity" and "responsible entity", in reference to *specific organizations*. For example, PJM is a registered entity and certified entity for the Balancing Authority functionFunctional entityFunctional Entity.

1. Reliability Coordinator

The Reliability Coordinator's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which will involve system and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange. The Reliability Coordinator does not receive tags, but may curtail Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority(ies) on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority(ies) to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator can deny a transmission outage request if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with maintaining System Operating Limits (SOLs). However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL violation and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOLs.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules

- Directing redispatch to alleviate congestion
- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority(ies) and Transmission Operator, can invoke public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority(ies) cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authority(ies).

Authority to perform its reliability functions. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable, for the Region in which the Reliability Coordinator Area is located. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority will be documented in and accepted by all the concerned Regions through their respective reliability plans.

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOLs, delineation of its authority and that of the Transmission Operator needs to be clearly defined in the reliability plan(s).

2. Balancing Authority

The Balancing Authority(ies) operates within the metered boundaries that establish the **Balancing Authority Area**. Every generator, transmission facility, and ~~e~~End-use ~~c~~Customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority(ies) Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation. The load-resource balance is measured by the Balancing Authority's Area Control Error (ACE).

NERC's Reliability Standards require that the Balancing Authority(ies) maintain its ACE within acceptable limits.

Maintaining resource-demand balance within the Balancing Authority(ies) Area requires four types of resource management, all of which are the Balancing Authority's responsibility:

- Frequency control through tie-line bias
- Regulation service deployment
- Load-following through economic dispatch
- Interchange implementation

Frequency control through tie-line bias. To maintain frequency within acceptable limits, the Balancing Authority(ies) controls resources within its Balancing Authority Area to meet its frequency bias obligation to the interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority(ies) controls a set of generators within its Balancing Authority(ies) Area that are capable of providing regulation service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority(ies) will in general also perform unit commitment and economic dispatch; however, in some markets, Generator Operators may be permitted to perform unit commitment and economic dispatch among the fleet of generators under their control and within the requirements accepted by the market operator.

Interchange implementation. The Balancing Authority(ies) receives Confirmed Interchange from one or more Interchange ~~Coordinator~~ Authority(ies), and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority(ies) receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority(ies) Area. The Balancing Authority(ies) provides this commitment and dispatch schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority(ies) approves an Arranged Interchange with respect to the ramping requirements of the generation that must increase or decrease to implement the Interchange. The Balancing Authority(ies) provides its approval or denial to the Interchange Coordinator Authority(ies).

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority(ies) can implement public appeals, demand-side management programs, and, ultimately load shedding. **Obviously, it must do this in concert with the Reliability Coordinator.**

Failure to balance. The Balancing Authority(ies) must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority(ies) cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

See "Managing Bilateral Interchange Transactions"

3. Planning Coordinator

The Planning Coordinator coordinates and integrates transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) and Resource Planner(s) within its area of purview. These activities range from review and integration of reinforcement and corrective action plans developed by the ~~f~~Functional ~~e~~Entities whose area of responsibility is within the Planning Coordinator's area with respect to established reliability needs to providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area.

While much of what the Planning Coordinator performs could be actually performed by a Transmission Planner, such as developing methodologies in conjunction with surrounding Transmission Planners, recognition of resource plans, assessing system performance consistent with reliability needs by itself, and collaborating with other Transmission Planners to assess impacts on the interconnected area, the Planning Coordinator by its very nature will generally take responsibility over a wider perspective than the Transmission Planners for which its coordinates. The Planning Coordinator generally conducts system performance assessments, in collaboration with other Planning Coordinators to consider transfer/flows across multiple Transmission Planner areas or intra and interstate areas such as generation dispatch scenarios caused by temperature or fuel extremes. Geographic size is not necessarily a critical consideration, it is the extent and impact of the electrical network that the planners have taken responsibility for assessing that determines whether an area is large enough for analysis and planning.

Although the ~~Functional~~ Model sets forth the concept of the Planning Coordinator and how a functional entity could perform as such, there may be situations or circumstances under actual organizational structures whereby a single entity does not exist that performs the Reliability Planning Function but rather is taken on by a number of entities, e.g. a group of Transmission Planners, or an organization such as a regional group formed within a region or possibly the Regional Entity itself. In all these cases the Reliability Planning Function is still performed in some manner by some entity or organization.

The boundaries for the Planning Coordinator area are basically defined by the location of the Bulk Electric System (BES) ~~f~~Facilities under the purview of the Planning Coordinator, i.e. those ~~f~~Facilities for which the Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of ~~f~~Facilities. The BES ~~f~~Facilities under its purview~~,~~ are generally contiguous and cover in aggregate the same areas as the Transmission Planners its coordinates. Traditionally transmission planning has been associated with one or more Transmission Owners, i.e. reinforcement and corrective action plans must be associated with certain Transmission Owner ~~f~~Facilities. Since transmission ownership may cross state or provincial or regional boundaries, the BES ~~f~~Facilities on one side of the Transmission Owner boundary may be in one Planning Coordinator area whereas the remaining ~~f~~Facilities may be in another. As such the Planning Coordinator area is not constrained to fit within a Reliability Coordinator or Transmission Operator Area. However, the Planning Coordinator area must cover at least one Transmission Planner Area and one Resource Planner area, or part thereof if either or both of these planner areas is larger than the Planning Coordinator area. On the other hand, there is the possibility that a Planning Coordinator area could be nested inside an even larger Planning

Coordinator area provided the smaller Planning Coordinator does in fact perform the appropriate system assessments. In this special case, the larger Planning Coordinator would perform the ultimate planning coordinating function for all the Resource Planners, Transmission Planner and smaller Planning Coordinator in its Area. As an example, some Independent System Operators (ISO) and Regional Transmission Organizations (RTO) perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Function at a broader scale.

In many areas, there may exist more than one Transmission Planner and Resource Planner, as well as a nested Planning Coordinator, within a Planning Coordinator area, each performing a different role demarcated primarily by their particular ~~f~~Function and scale (area-wise) of assessments performed. In these cases, delineation of the role of the various F~~f~~unctional Ee~~e~~ntities needs to be clearly defined in the regional reliability plan(s).

The Planning Coordinator is not responsible for implementing the transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and transmission facilities are placed into service in a timely manner through the Resource Planners, Transmission Planners, and possibly others through the coordinated planning process.

4. Transmission Planner

The Transmission Planner develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area ~~of purview~~.

The boundaries for the Transmission Planner area are basically defined by the location of the BES~~Bulk Electric System~~ ~~f~~Facilities under the purview of the Transmission Planner, i.e. those facilities for which the Transmission Planner develops reinforcement and ~~c~~Corrective ~~a~~Action ~~p~~Plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner's area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available ~~i~~Interconnection wide models. The BES facilities in its area, i.e. under its purview, are generally contiguous.

Traditionally transmission planning has been associated with one or more Transmission Owners, i.e. reinforcement and ~~c~~Corrective ~~a~~Action ~~p~~Plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner ~~A~~area while the remaining facilities may be in another. As such, the Transmission Planner ~~A~~area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner ~~A~~area can only be smaller than or equal to the area of its related Planning Coordinator.

Develop Transmission Expansion Plans. The Transmission Planner evaluates the facilities that will be needed in response to long-term requests for ~~t~~Transmission ~~s~~Service, and needed to integrate new generation, transmission, and ~~e~~End-use ~~c~~Customers into the BES~~Bulk Electric Systems~~. In developing plans for ~~t~~Transmission ~~s~~Service and interconnection requests, the Transmission Planner is expected to coordinate plans or engage in joint planning with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems.

Based on customer requests for ~~t~~Transmission ~~s~~Service, ~~n~~Native ~~l~~Load growth, changes in existing ~~n~~Native ~~l~~Load, and the planning procedures and protocols established for their Transmission Planning ~~A~~areas, the Transmission Planners will develop transmission plans to accommodate long-term ~~f~~Firm ~~t~~Transmission ~~s~~Service requests and ~~n~~Native ~~l~~Load requirements with due regard to established reliability needs. While developing these plans, the Transmission Planner may provide alternate solutions and evaluate alternatives suggested by entities requesting customer service.

The Transmission Planner~~s~~ provide~~s~~ its transmission plans to its Planning Coordinator for review to ensure impacts on the interconnected systems are duly addressed. In reporting its transmission expansion plan to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether ~~c~~Corrective Action ~~p~~Plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected BES~~Bulk Electric System~~ requirements.

5. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.

Note: The term "resource" is to be understood to include supply resources and demand resources (such as dispatchable loads).

The boundaries for the Resource Planner area are basically defined by the location of the specific loads being considered for resource adequacy. The loads under considerations are generally contiguous and form the fundamental input for analysis of resources such as loss of load studies. The Resource Planning Ff~~f~~unction may be performed by one or more Resource Planners within a Planning Coordinator area, Transmission Planner or Reliability Coordinator Area; however, the Resource Planning Function could be performed by one Resource Planner that covers one, or more than one, Planning Coordinator area, Transmission Planner Area or Reliability Coordinator Area. As such the Resource Planner area is not constrained to fit within the footprint of any other ~~f~~Functional Ee~~e~~ntity. The analysis and development of resource plans by their very nature will need to consider generation capacity and other resources outside the area defined by the specific loads as well as the transmission capability to access those resources.

In some markets, market rules may require the same organization to assume the role of both the Planning Coordinator and the Resource Planner. For example, in those markets where there are no entities responsible for or obligated to serve load, the Planning Coordinator will generally assume the Resource Planner's role. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market and performs the Resource Planning Function.

Types of Resource Planning
Resource planning, in a generic sense, may be divided into two types:

- Planning conducted by an organization under the authority of legislation, regulation order, tariff or market rule. Such planning will typically be conducted in an open process and subject to industry, public and stakeholder review. It will have as one objective, ensuring resource adequacy.
- Planning directed to identifying and realizing commercial opportunities. Such plans will typically be commercially sensitive, may not be made public before required for the plan to be implemented, and will not be directed to ensuring resource adequacy.

The Resource Planner described in the Model is associated with the former type of planning, i.e., planning having a mandate to ensure resource adequacy.

The latter type of planning, which is driven primarily by commercial opportunity, may be viewed as an activity associated with generation ownership. However, resource planning that is purely commercially-driven clearly will have an impact on resource adequacy. The Resource Planner, with its mandate for resource adequacy, must reflect to the extent possible commercially-directed planning affecting its Resource Planner area.

6. Transmission Operator

The Transmission Operator operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in system restoration.

Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.

Bundled with the Reliability Coordinator or Transmission Owner. A single organization may be the Ff~~f~~unction Ee~~e~~ntity for multiple Functions. In such a case, the Ff~~f~~unctional Entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these Ff~~f~~unctional ~~e~~Entities.

Bundled with Reliability Coordinator. For example, consider an RTO with several members. The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator ~~T~~tasks to its members.

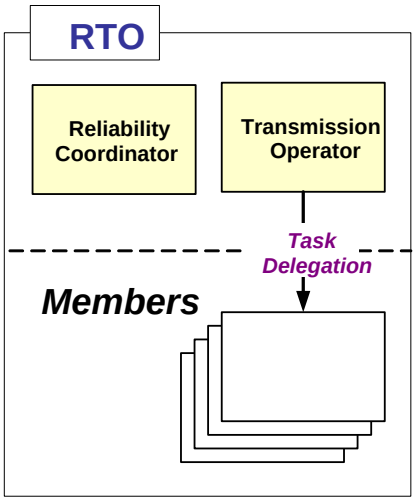


Figure 1 - Transmission Operator bundled with Reliability Coordinator.

Bundled with the Transmission Owner. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the Model views the RTO as responsible for complying with Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such.

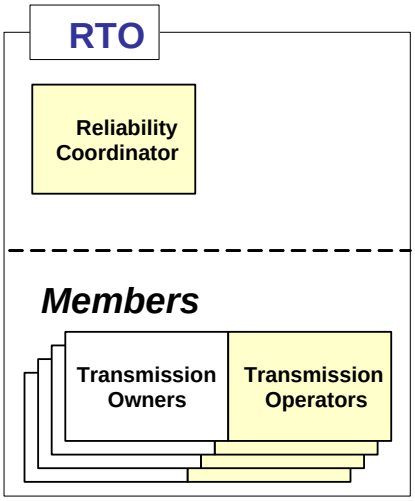


Figure 2 – Transmission Operator bundled with Transmission Owner

7. Interchange ~~Coordinator~~ Authority

The Interchange ~~Coordinator~~ Authority(ies) collects approvals or denials for Arranged Interchange from Balancing Authorities and Transmission Service Providers and verifies the validity of the source and sink. The NERC Tag Authority provides this service that had been assigned to the Sink Balancing Authority(ies).

The Interchange ~~Coordinator~~ Authority(ies) provides the Balancing Authority(ies) with the individual bilateral Arranged Interchange. The Balancing Authority(ies) must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority(ies) in those cases where a generator or load is interrupted. The Balancing Authority(ies) then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority(ies). The net Interchange Schedule for each neighboring Balancing Authority(ies) is used by the Receiving Balancing Authority(ies) for checkout with the neighboring Balancing Authority(ies).

All bilateral Interchange Transactions *that cross a Balancing Authority(ies) Area boundary* are coordinated through the Interchange ~~Coordinator~~ Authority(ies).

While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange F~~f~~unction will be assigned to an actual organization. A Balancing Authority(ies) may serve as its own Interchange ~~Coordinator~~ Authority(ies) or have this service provided by a separate organization.

Assessing ramping capability and connectivity. The Balancing Authority(ies) approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange ~~Coordinator~~ Authority(ies). The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the Interchange ~~Coordinator~~ Authority(ies).

Ensuring balanced, valid Interchange Transactions. The Interchange ~~Coordinator~~ Authority(ies) also ensures that the resulting Confirmed Interchange Transactions is balanced and valid prior to physical delivery. This means:

- The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and
- All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange ~~Coordinator~~ Authority(ies) direct the Balancing Authorities to implement the Transaction. If any of these entities — TSPs, or BAs — does not approve the Arranged Transaction, then the Interchange ~~Coordinator~~ Authority(ies) does not authorize the Transaction to become Confirmed Interchange.

Curtailments. The Interchange ~~Coordinator~~ Authority(ies) coordinates ~~c~~Curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange ~~Coordinator~~

Authority(ies) also communicates and coordinates the resulting modified Arranged Interchange that result from the ~~c~~Curtailments.

8. Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In most cases, the organization serving as Transmission Service Provider is also the market operator.

Role in approving Interchange. The Transmission Service Provider approves Arranged Interchange by comparing the ~~t~~Transmission ~~s~~Service previously arranged by the ~~t~~Transmission customer ~~(Purchasing-Selling Entity, Generator Owner, Load-Serving Entity)~~ with the transmission information supplied by the Interchange ~~Coordinator~~ Authority(ies). The Transmission Service Provider also ensures that there is a contiguous transmission path and that adjacent TSPs are on the scheduling path. The Transmission Service Provider then provides its approval or denial to the Interchange ~~Coordinator~~ Authority(ies).

Providing Transmission Service. As its name implies, the Transmission Service Provider provides ~~t~~Transmission ~~s~~Service to ~~t~~Transmission ~~c~~Customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for ~~t~~Transmission ~~s~~Service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider does not itself have a role in maintaining system reliability in real time — that is done by the Reliability Coordinator and Transmission Operator.

The Transmission Service Provider arranges for transmission loss compensation with the Balancing Authority(ies).

9. Transmission Owner

The Transmission Owner owns its transmission ~~f~~Facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, and Transmission Planner and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other ~~t~~Transmission ~~c~~Customers that would detail the terms of the interconnection between the owner and customer.

Relationship with the Transmission Operator. The organization serving as Transmission Owner may operate its transmission ~~f~~Facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission ~~f~~Facilities.

See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"

10. Distribution Provider

The Distribution Provider provides the physical connection between the ~~e~~End-use ~~c~~Customers and the electric system, including customers served at transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution ~~f~~Function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider and not directly connected to the B~~ulk E~~~~lectric S~~~~ystem~~.

The Distribution Provider maintains "local" safety and reliability. The Distribution Provider provides the switches and re-closers necessary for emergency action. The Distribution Provider may need to demonstrate load-shedding capability to the Balancing Authority(ies) and Transmission Operator.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these ~~f~~Functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these ~~f~~Functions together.

11. Generator Operator

The Generator Owner may operate its generating ~~f~~Facilities or designate a separate organization to perform the Generator Operation Function.

The Generator Operator operates, or directs the operation of generation ~~f~~Facilities. The Generator Operator supports the needs of the BES~~Bulk Electric System~~ up to the limits of the generating ~~f~~Facilities in its purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.

Relationship with the Generator Owner. The organization that serves as Generator Operator may also be the owner of the generation ~~f~~Facilities it operates; or it may be a separate organization designated by the Generator Owner to operate the ~~f~~Facilities. The Generator Operator receives maintenance and performance verification schedules from the Generator Owner, and develops operating and unit commitment plans based on these schedules.

Relationship with the Transmission Operator. The Generator Operator provides Interconnected Operations Service~~reliability-related services~~ through arrangements or by direction from the Transmission Operator for support of the BES~~Bulk Electric System~~. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.

Relationship with the Balancing Authority(ies). The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority(ies).

Relationship with the Reliability Coordinator. The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the B~~ulk~~ E~~lectric~~ S~~ystem~~.

Relationship with Purchasing-Selling-Entity. The Generator Operator receives notice of Arranged Interchange approved by the Purchasing-Selling-Entity.

12. Generator Owner

The Generator Owner owns its generation ~~f~~Facilities and provides for the maintenance of those ~~f~~Facilities. It also provides verified equipment operating limits and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner and Planning Coordinator.

In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The organization serving as Generator Owner may operate generation ~~f~~Facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and ~~f~~Facility verification, or may arrange with another organization to do so.

13. Purchasing-Selling Entity

The Purchasing-Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load-Serving Entity (LSE). The PSE also arranges for ~~t~~Transmission ~~s~~Service with the Transmission Service Provider that provides ~~t~~Transmission ~~s~~Service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority(ies) Areas by submitting a Request for Interchange (RFI) to the Interchange ~~Coordinator~~ Authority(ies).

14. Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy to its ~~e~~End-use ~~c~~Customers, but does not provide distribution services ("wires"). The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.

Today, organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide, or have contracts with other Generator Owners for capacity and energy to serve the LSE's customers, or purchase capacity and energy from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its generation (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority(ies), which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for reliability-related services through the Market Operator (if the LSE is part of a market or pool) or directly from Generator Owners or loads.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Distribution Provider, the Load-Serving Entity, does not have ~~Bulk Electric System~~BES assets ("wires") but does take title to energy. However, while these ~~f~~Functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these ~~f~~Functions together.

The ~~Functional~~ Model assigns to the LSE the identification of loads for ~~c~~Curtailment and the development of load profiles and load forecasts. Please see Section II, 114: Roles in Load Curtailment for more detailed information.

The LSE communicates requests for voluntary ~~c~~Curtailment to the appropriate ~~e~~End-use ~~c~~Customer loads, thereby ensuring that these loads will in fact be curtailed.

15. Compliance Enforcement Authority

NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.

16. Standards Developer

The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section II.

17. Market Operator (Resource Integrator)

Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions.

The associated Ffunctional Eentity is the Market Operator (Resource Integrator). ~~The term Resource Integrator replaces Resource Dispatcher used in Version 3 of the Model.~~ This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority(ies).

The Market Operator is described further in Section II, Technical Discussions.

18. Reliability Assurer

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function~~ Function ~~replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function~~Function~~.~~

~~The change to~~ Use of the term Reliability Assurer ~~reflected~~ reflects the fact that ~~a name specific to the Model is preferable to a name already in use in another context. Moreover, since~~ this ~~-~~Function can be performed on other than a regional basis, the ~~Functional~~ Model allows for the assignment to be made to an organization other than a Regional Entity.

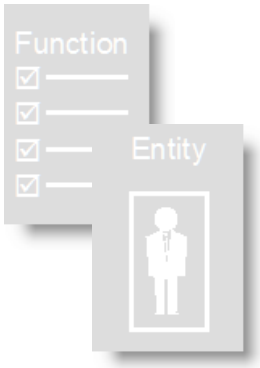
~~The changes therefore provide NERC with flexibility in assigning the F~~functional ~~E~~entity ~~for Reliability Assurance.~~

The role of the Reliability Assurer may be considered to provide "defense-in-depth". That is, the Reliability Assurer provides an independent assessment of ~~T~~task ~~performed~~ by other ~~F~~functional ~~e~~ntities~~, or facilitates or coordinates such Task~~. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the ~~T~~tasks that might be performed:

- Perform high level evaluations, such as at a regional or ~~i~~interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.
- Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.
- Perform high-level evaluations, such as at a regional or ~~i~~interconnection level, of ~~p~~Protection ~~s~~Systems as they relate to the reliability of the BES~~Bulk Electric System~~.
- Perform disturbance analysis evaluations.

The selection of particular ~~T~~task~~s~~ for the Reliability Assurer will reflect NERC's judgment on which ~~T~~task~~s~~ merit such a "defense-in-depth" approach.

Section II — Technical Discussions



1. General Clarifications of the Functional Model

The general features of the ~~Functional~~ Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:

The ~~NERC Reliability Functional Model ("the Model")~~ Model provides the framework for the development and application of NERC's Reliability Standards, as follows:

- *The Model describes a set of Functions that are performed to ensure the reliability of the ~~Bulk Electric System~~BES. Each Function consists of a set of related reliability ~~T~~task~~s~~. The Model assigns each Function to a ~~f~~Functional E~~e~~ntity, that is, the entity that performs the Function's ~~T~~tasks. The Model also describes the interrelationships between that ~~f~~Functional E~~e~~ntity and other F~~f~~unctional ~~e~~Entities ~~(that perform other Function).~~*
- *NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a ~~f~~Functional E~~e~~ntity, as defined in the Model.*
- *This is possible because a given standard requirement will be logically related to a ~~T~~task within a Function. A standards requirement will be very specific whereas a ~~T~~task will be more general in nature.*
- *NERC's compliance processes require specific organizations to register as F~~f~~unctional E~~e~~ntities and comply with standards requirements assigned to the F~~f~~unctional E~~e~~ntities.*
- *The Model's Functions and F~~f~~unctional E~~e~~ntities also provide for consistency and compatibility among different Reliability Standards.*

The ~~NERC Reliability Functional Model ("the Model")~~Model does NOT address:

- *Entity Certification*
- *Registration*
- *Compliance*
- *Sanctions*

There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for mis-interpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a Reliability ~~s~~Standard, and does not have compliance requirements. The Model is a guideline for the development of Reliability ~~s~~Standards and their applicability; it is not a NERC ~~r~~Requirement. Standards developers are not required to include tasks envisioned in the ~~m~~Model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards ~~r~~Requirements take precedence over the Model.

A Functional Entity is not an actual organization. The Model describes ~~T~~tasks performed by F~~f~~unctional E~~e~~ntities, which are in effect generic *classes or categories* of organizations — the Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a ~~f~~Functional E~~e~~ntity; the Model does not reference PJM and MISO, which are specific organizations. It is through NERC's registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.

Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

Every Function has an associated ~~f~~Functional E~~e~~ntity. A Function is a set of related reliability ~~T~~tasks; whereas the ~~f~~Functional E~~e~~ntity is the name given to the category of organization that performs these ~~T~~tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated ~~f~~Functional E~~e~~ntity underneath.

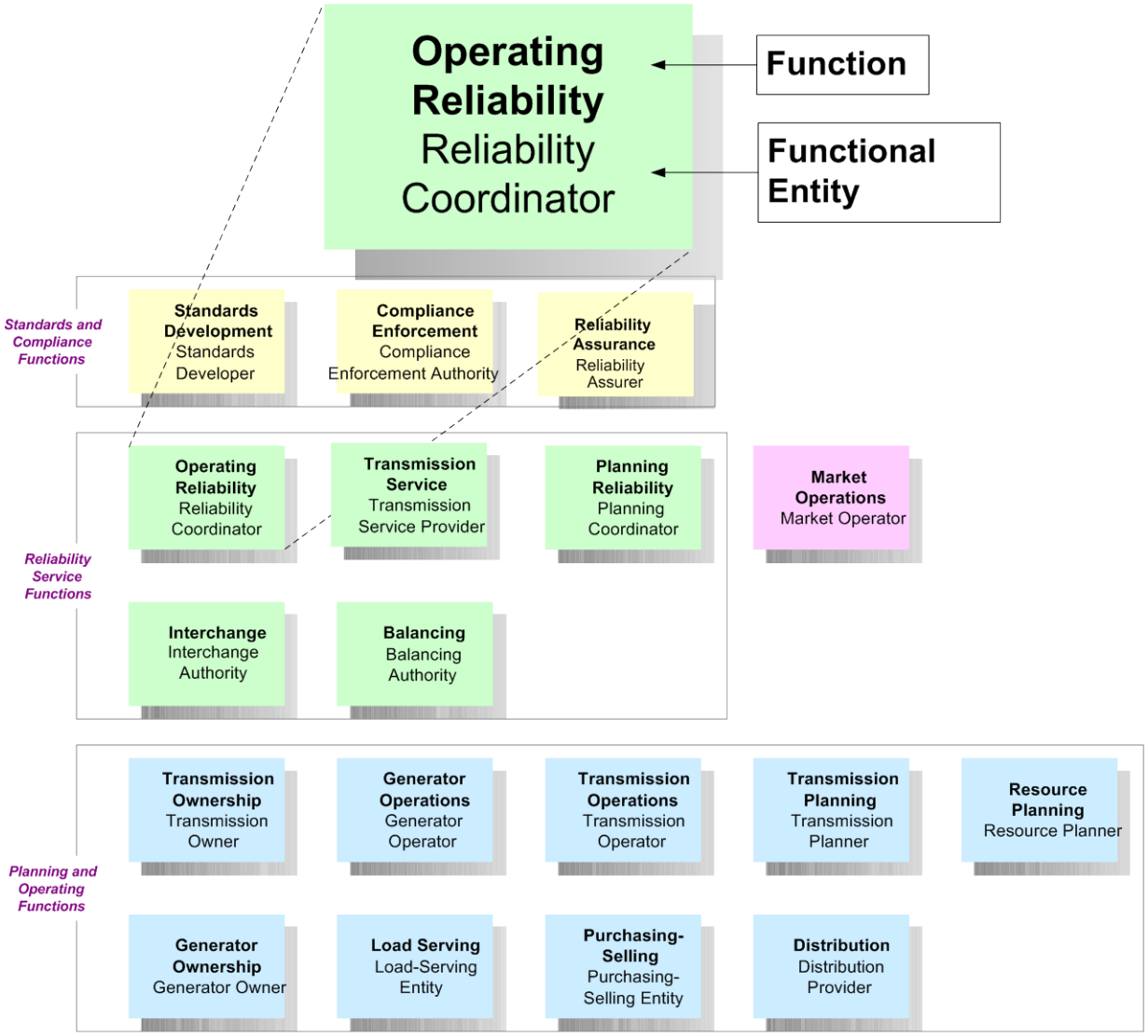


Figure 3 – Function and Functional Entity

Organizations, such as R~~egional~~ T~~ransmission~~ O~~rganization~~s or integrated utilities, may register with NERC as ~~Responsible~~ Functional Entities by identifying which Functions they perform.

For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority(ies), and a Transmission Service Provider. In this case we say that the RTO is the **~~Responsible~~ Functional Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has "rolled up" these three Functions and is responsible for ensuring that the ~~T~~tasks~~s~~ within each of those Functions are performed and all applicable standards requirements met.

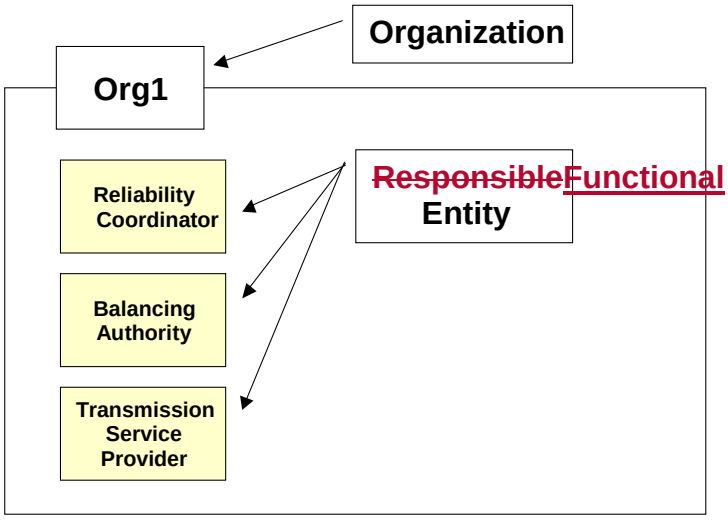


Figure 4 — Organizations may "roll up" more than one ~~f~~Functional ~~e~~Entity.

2. Reliability Standards

The ~~Functional~~ Model describes the Standard Development Function and the Standards Developer Ff~~f~~unctional Ee~~e~~ntity~~-~~ and how these are related to Reliability Standards.

Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:

1. **Reliability Standards Developed at the North American Level Within NERC**
   NERC, under regulatory authority, develops and maintains Reliability Standards using the NERC Reliability Standards Development Procedures. The Reliability ~~s~~Standards are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.

   NERC can use the Reliability Standards Development Procedures to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:

   - Entity Variance that applies to an area less than a NERC Region
   - Regional Variance that applies to a NERC Region but less than an Interconnection
   - Regional Variance that applies to a NERC Region on an Interconnection-wide basis.

2. **Reliability Standards Developed Within a Regional Entity**
   Regional Entities may develop and propose to NERC ~~r~~Regional ~~r~~Reliability ~~s~~Standards that:

   - Set more stringent reliability requirements than the NERC Reliability Standard
   - Cover matters not covered by an existing NERC Reliability Standard.

   Alternatively, NERC may direct Regional Entities to develop a ~~r~~Regional ~~r~~Reliability ~~s~~Standard in order to implement a NERC Reliability Standard. Such a ~~r~~Regional ~~r~~Reliability ~~s~~Standard, upon approval by NERC, becomes part of the NERC Reliability Standard.

   Regional Entities must use a NERC-approved development process to develop these ~~r~~Regional ~~r~~Reliability ~~s~~Standards. Such ~~r~~Regional ~~r~~Reliability ~~s~~Standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the ~~r~~Regional ~~r~~Reliability ~~s~~Standard as an:

   - Interconnection-wide ~~r~~Regional Reliability ~~s~~Standard, or
   - Non-Interconnection-wide ~~r~~Regional Reliability ~~s~~Standard.

Regional Criteria. Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the ~~(NERC) Functional~~ Model.

3. Market Operations (Resource Integration)

Market Operations is not a reliability Function. NERC does not assign standards requirements to the Market Operator.

Nevertheless, Market Operations, a commercial or market ~~f~~Function, is included in the ~~Functional~~ Model, in order to provide an interface point between reliability and commercial ~~f~~Functions.

The role of the Market Operator also varies in design and responsibilities, but all Market Operators perform a resource integration task of one form or another under a set of market rules that are recognized by a state, federal, or provincial regulator. Resource integration is discussed further in the following section II- 4, ~~Functional~~ Model and Market Structures.

Versions 4 and 5.1 of the Model refer to the entity as "Market Operator (Resource Integrator)", where Resource Integrator is seen as a better term than Market Operator in areas not having a full-service market. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.

1. **The Market Operator in a Full-Service Market.**
   A full-service market is one which offers both the commercial services such as integrating resources ahead of Real-time and settlement after the completion of Implemented Interchange and dispatch cycles, and implement the resource plan in Real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).

   This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority(ies) for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority(ies) will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the Market Operator and the Balancing Authority(ies). A full-service Market Operator performs resource integration task and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time
- Integrating scheduled interchange into that generation plan

- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority(ies) ahead of real time.

The Balancing Authority(ies) receives the plan, and implements it in real time.

2. **The Market Operator Where There is not a Full-Service Market.**
   In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority(ies), and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.

   In addition, there are jurisdictions that use a model other than full-service market and vertically-integrated utility, in particular bilateral Interchange Transactions. In this case, the organization serving as Balancing Authority(ies) will also be the Market Operator, operating on the basis of net interchange.

4. The Functional Model and Market Structures

This section explains how the ~~Functiona~~l Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.

Resource Integration Protocol. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section II-3, Market Operations (Resource Integration). The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the ~~Functiona~~l Model can accommodate either type of protocol.

Bid-Based Resource Integration. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority(ies) with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Redispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority(ies). The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs.

Multiple Balancing Authorities Within a Market Area. If the Market Area includes more than one Balancing Authority(ies) Area, then the Market Operator will also provide each Balancing Authority(ies) with the net "interchange" schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

Task	No Full-Service Market: Vertically Integrated Structure	Full-Service Market: Unbundled Structure
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.
Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (e.g., bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority(ies), Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required, and designates those units that provide the regulation service. Utility (as Balancing Authority(ies)) uses this information in its economic dispatch.	Balancing Authority(ies), along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority(ies)) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority(ies) directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority(ies) pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority(ies) asks the Market Operator for a new dispatch plan.

5. Providing and Deploying Ancillary and Reliability-Related Services

Tariff Domain — Requirement for Ancillary Services. The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):

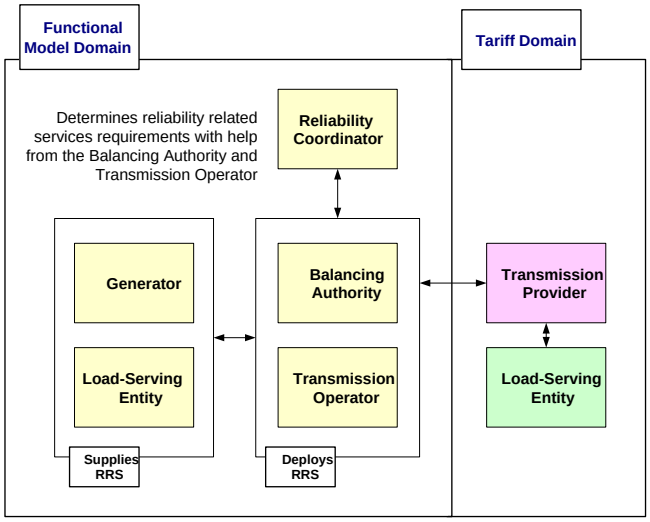


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

Scheduling, system control, and dispatch

1. Reactive supply and voltage control from generation.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide the following services to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

2. Energy imbalance
3. Regulation and frequency response
4. Operating reserve — spinning
5. Operating reserve — supplemental.
6. Generator Imbalance

Functional Model Domain — Reliability-related Services. The term "reliability-related services" means those services other than the supply of energy for load that are physically provided by generators, transmitters and loads in order to maintain reliability.

Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads. Certain transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic

transmission service. In addition, loads may provide reserves through load-shedding or demand-side management, and may also provide frequency response.

Figure 5 shows how Ancillary Services in the “tariff domain” could be served by reliability-related services in the "reliability domain". The ~~Functional~~ Model explains that the Balancing Authority(ies), alone or in coordination with the Reliability Coordinator, determines the amount required and arranges for reliability-related services to ensure balance:

- The Balancing Authority(ies) determines regulation, load following, frequency response, and contingency reserves, etc., and deploys these as reliability-related services.
- The Transmission Operator determines the reliability-related services necessary to meet its reactive power requirements to maintain transmission voltage within operating limits, and deploys these as its set of reliability-related services.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for Black Start capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the transmission system.

Through its Reliability Standards, NERC holds organizations (those registered as Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services. The quantity of and processes used to deploy those reliability-related services depend on the Regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own reliability-related services, using these processes and procedures in a manner that ensures compliance with the standards’ requirements.

6. Managing Bilateral Interchange Transactions — Basic Concepts

Interchange that crosses multiple Balancing Authority(ies) (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority(ies)-to-Balancing Authority(ies) Interchange Transactions, with the Sink Balancing Authority(ies) designated as the "manager" (the "Tag Authority").

The ~~Functional~~ Model recognizes this Interchange process as the current Industry practice and includes BA-to-BA "after hour" checkout for net Interchange between adjacent Balancing Authority(ies). Also, the Interchange ~~Coordinator~~ Authority(ies) ~~f~~Function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IA~~C~~ receives approvals that recognize ramping capability. The IA~~C~~ also communicates the individual Interchange information to all involved parties (Figure 6).

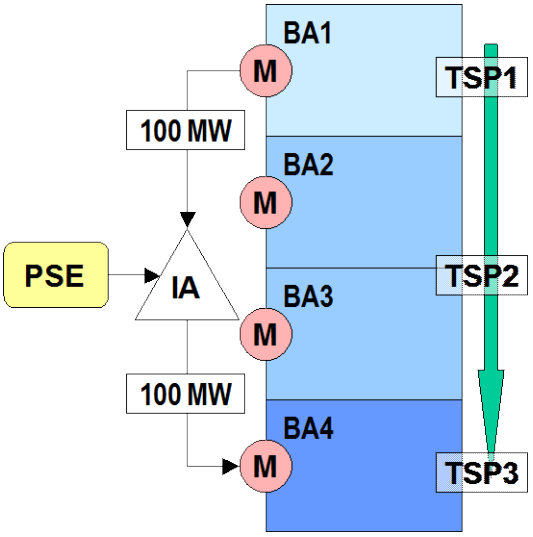


Figure 6 — The Interchange ~~Coordinator~~ Authority(ies) manages transactions between the source and sink Balancing Authority(ies).

Managing Bilateral Interchange Transactions — Allowable Concept

The ~~Functional~~ Model does not prevent Balancing Authorities from scheduling Interchange with Interchange ~~Coordinator~~ Authority(ies) (IA~~C~~). The IA~~C~~s would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IA~~C~~ manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

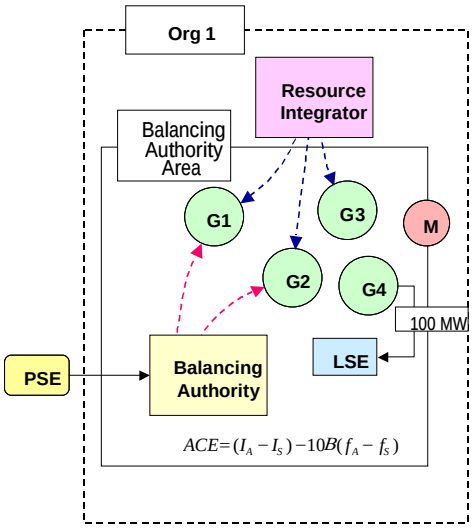


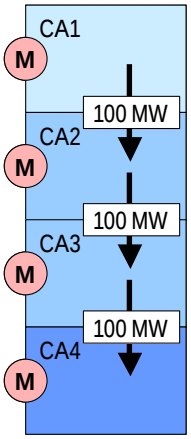
Figure 7 The Purchase-Selling Entity submits the bilateral transaction to the Balancing Authority(ies) intra-BA transactions.

Interchange Transactions within a Balancing Authority(ies) Area. A bilateral Interchange within a Balancing Authority(ies) Area does not require Interchange ~~Coordinator~~ Authority(ies) authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority(ies) who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Interchange, and to the Reliability Coordinator for reliability assessment.

The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authority(ies) would use if this type of Interchange concept were applied.

Checkout under Existing NERC Practice Figure 8			
Control Area	**Actual from Tie Meters**	**Schedule with CA**	**Inadvertent**
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0
Potential Future Checkout Figure 9			
Balancing Authority	**Actual from Tie Meters**	**Schedule with IAC**	**Inadvertent**
BA1	+100 to BA2	+100 to IAC	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IAC	0

Figure 8



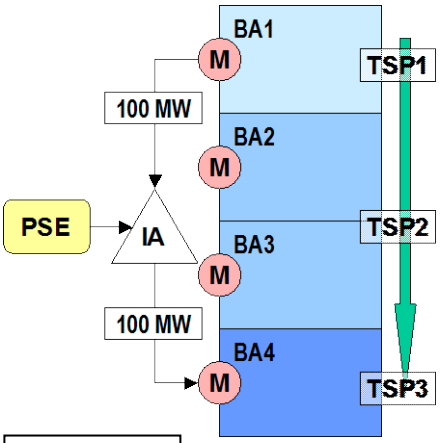


Figure 9

7. Managing Bilateral Interchange — Scheduling EntitiesAgents

Some Transmission Providers provide a Scheduling EntityAgent service for their Balancing Authority(ies) members. The Scheduling Agent Entity provides a single point of contact for all Interchange into or out of those Balancing Authority(ies). For example, the Southwest Power Pool serves as a Scheduling EntityAgent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority(ies) by way of the SPP as the Scheduling EntityAgent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 10, two Interchange Coordinator Authority(ies) arrange a total of 225 MW with the Scheduling EntityAgent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1

IS3 = 50 MW into BA3

IS4 = 75 MW into BA4

IS2 = 0

The Scheduling EntityAgent must ensure that the sum of the Interchange from all Interchange Coordinator Authorities is exactly equal to the sum of the Interchange from the Scheduling EntityAgent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

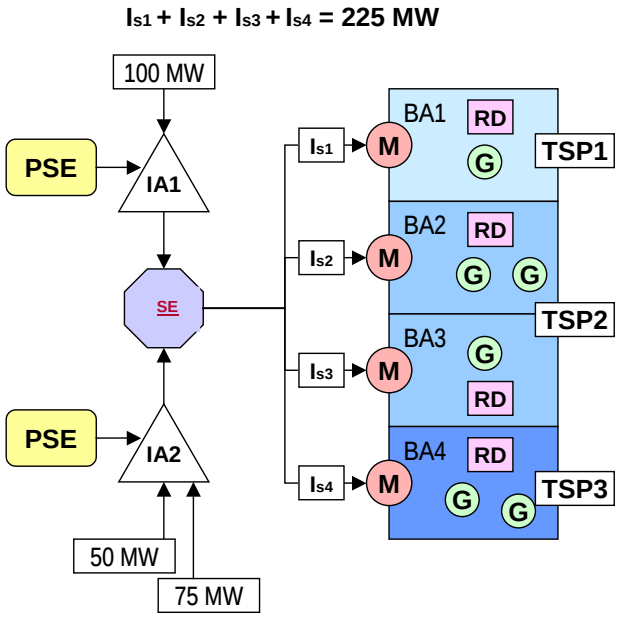


Figure 10 - The Scheduling EntityAgent divides a 100 MW transaction among a group of Balancing Authorities.

If the Balancing Authority(ies) use a Scheduling EntityAgent, then the Interchange Coordinator Authority(ies) will request approvals from the Scheduling EntityAgent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator Authority(ies) will also notify the Scheduling EntityAgent of any Interchange curtailments.

Because Interchange scheduling is an integral fFunction of the Balancing Authority(ies), the Functional Model Working Group defines that the Scheduling EntityAgent is actuallyas anas an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling EntityAgent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling EntityAgent would need to be certified and monitored to ensure that it handled the Interchange properly.

8. Non-coincident Resource Integrator and Balancing Authority Areas

Bilaterals between Market Areas. In the examples above, each Balancing Authority(ies) Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority(ies) Areas, we may be faced with a bilateral Interchange -whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority(ies) within that area. In this situation, the Interchange ~~Coordinator~~ Authority(ies) interfaces with the Scheduling ~~Agent~~ Entity for the Market Area. Then the Scheduling ~~Agent~~Entity, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority(ies) Areas.

As was explained in the technical discussion on reliability-related services, the Scheduling ~~Agent~~ Entity ensures that the RDIS are properly allocated to the Balancing Authorities.

Now we can combine the Scheduling ~~Agent's~~ Entity's management of RDIS with bilateral Interchange Transactions as shown in Figure11.

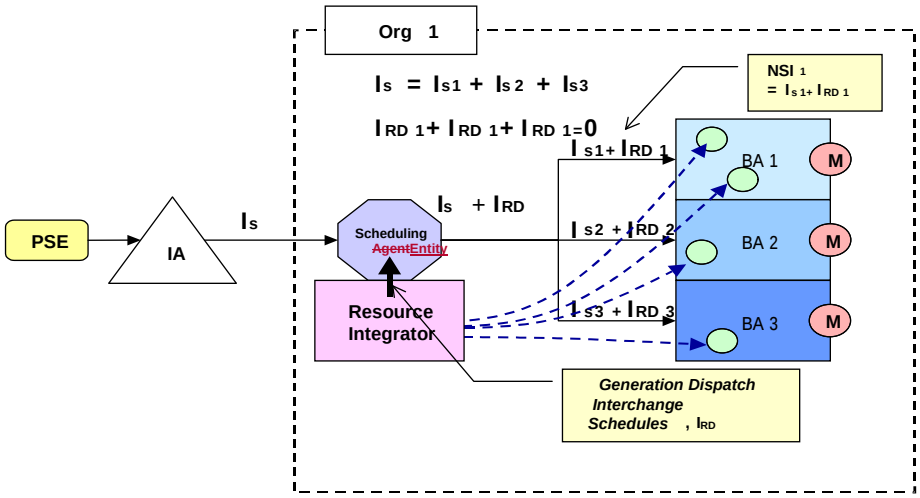


Figure 11 - The Scheduling ~~Agent~~Entity manages bilateral Interchange Transactions in to or out of the Market Area as well as the Interchange Schedules that result from the economic dispatch or market operations.

Bilaterals between Balancing Authorities within the same Market Area. Bilateral Interchange between two Balancing Authorities within the same Market Area does not require Interchange ~~Coordinator~~ Authority(ies) management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Coordinator. In the example in Figure 12 the Purchasing-Selling Entity has submitted a 100 MW request for Interchange from BA1 to BA3 directly to the Scheduling ~~Agent~~Entity, who would

then coordinate the transaction between the source and sink Balancing Authority(ies). The Scheduling ~~Agent~~ Entity then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.

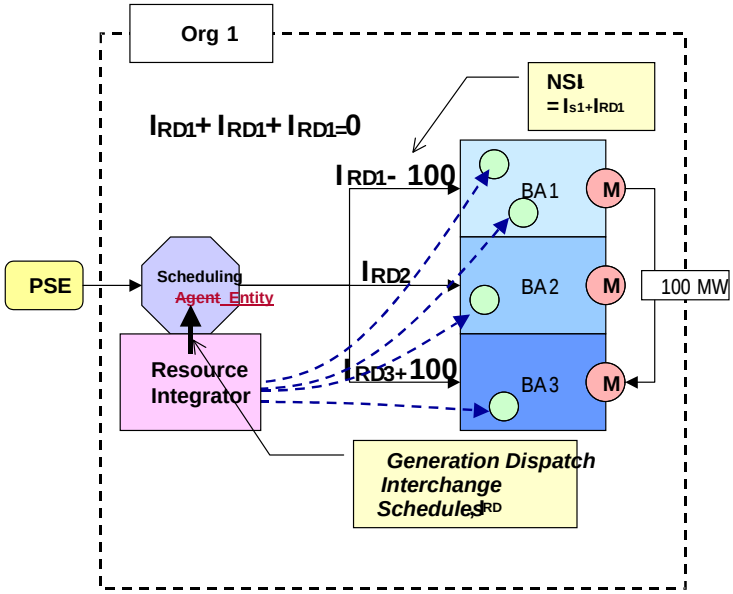


Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Entity~~Agent~~ when the bilateral transaction is within the same Market Area.

9. Implementing the Interchange ~~Coordinator~~ Authority

The IA~~C~~ T~~t~~asks are being performed by the organization registered as BAs, specifically the "~~s~~Sink BA"[2] for a particular interchange transaction. It has been noted that the ~~Functional~~ Model could in principle have assigned the IA~~C~~ T~~t~~asks to the BA and avoided the need for a separate Interchange ~~f~~Function. This approach was not followed because it was envisioned in the future that the IA~~C~~ T~~t~~asks could be performed by entities other than a BA, a possibility that is allowed for by defining the IA~~C~~ separate from the BA. Therefore, the ~~Functional~~ Model *accommodates* the sink BA as the IA~~C~~, but does not *require* it.

The implementation of the IA~~C~~ extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IC.

The NERC direction regarding registering of IA~~C~~s is compatible with the approach taken in the Model:

- There is a need for a separate Interchange ~~Coordinator~~ Authority(ies) F~~f~~unctional E~~e~~ntity.
- Allowance is made for BAs to register as IA~~C~~s, but organizations that are not BAs are not precluded from doing so.
- The IA~~C~~ is an entity, not a software tool.

The remainder of this section clarifies the context and need for an IA~~C~~ from the perspective of the Model, by describing the associated reliability tasks and their implications. As such, it may be of use to those involved in registration processes.

INTERCHANGE PRACTICE

Background

To help ensure reliability, *"requests" for interchange transactions* (Arranged Interchange) must be approved before that request is allowed to become an "implemented" interchange transaction (Confirmed Interchange). Without approvals, it is possible that the sum of all interchange schedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every BA were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net ~~s~~Scheduled Interchange being in error.

Historically, approvals were handled on a control area to control area basis. Net ~~i~~Interchange ~~s~~Schedules between neighbors were checked and approved prior to implementation. Only if there were disagreements did individual requests get checked. This pragmatic practice served the industry well — but not perfectly. When given control areas did not take the time to compute their own Net Scheduled ~~i~~Interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual schedules were active

[2] ~~That is, the BA in whose area the bilateral interchange transaction terminates.~~

on one side of the control area, but not on the other side. Not until serious operational symptoms arose (e.g., unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The ~~Functional~~ Model's inclusion of an IA~~C~~ recognizes a reliability concern regarding responsibility for approving a request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every transaction that a PSE desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those transactions.

Today, the approval and communication are implemented in a two-step process — each step focusing on different quantities. One step focuses on the individual transactions and their respective characteristics. This step is carried out by a tagging authority. The other step focuses on implementing Net Interchange ~~s~~Schedules (i.e., the net of the transactions that were approved). This step is carried out by neighboring BAs. This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.

For example, if the tagging authority were the root cause of non-compliance (such as a computer error) that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout, then no one would be held non-compliant, if no entity is registered as IA~~C~~ for the transaction. If a BA_{left} accepts a Net Interchange Schedule from BA_{center} but the transactions within that Net do not agree with the complementary transactions of the accepted Net Interchange Schedule between BA_{center} and BA_{right}, then again no one can be held non-compliant if no one is registered as IA~~C~~.

What is in place today is the NERC Tagging Specification, under which each ~~s~~Sink BA is responsible for providing Tagging Services, either directly or by arranging with a third party to provide this service as its agent.[3] However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.

An important question for many within industry is "how do you implement the concept of an Interchange ~~Coordinator~~ Authority(ies) (IA~~C~~)".

The initial step of the implementation requirements has been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA ~~(now referred to as the IC)~~. The Electronic Tagging Functional Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority(ies) operations (i.e., Sink BA).

[3]Electronic Tagging Functional Specification, ver 1.8.0, approved Nov 7, 2007, http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc **)**

To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) was revised to map the Tagging Service requirement from the Balancing Authority(ies) to the entity performing the Interchange ~~f~~Function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).

10. Distribution Provider as Load-Serving Entity

FERC Order of October 16, 2008[4] approved a NERC filing that proposed, as a short-term solution, revisions to the NERC Statement of Compliance Registry Criteria (Registry Criteria) to provide that a ~~d~~Distribution ~~p~~Provider to whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.

The Order requires that "the Distribution Provider to whose system the electric loads in retail choice areas are connected are to be registered as the LSE for all loads connected to its system for the purpose of compliance with NERC's approved ~~r~~Reliability ~~s~~Standards applicable to LSEs."

NERC states that, with respect to load served by retail choice through load aggregators, there may not be a clear agreement in place between the ~~d~~Distribution ~~p~~Providers and the load aggregators delineating the responsibilities between the parties regarding compliance with mandatory Reliability Standards. Further, the compliance filing explains that "NERC will exercise its discretion in the application of penalties or sanctions upon Distribution Providers who are providing this information on the behalf of loads served by a retail choice load aggregator until such time as both entities are either registered or the standards are updated to clarify the responsibilities for each party as ultimately i~~n~~dentified in the longer-term solution proposed by NERC."

NERC stated that DPs have both the infrastructure and access to information to enable them to comply with the Reliability Standards that apply to LSEs. Moreover, ~~d~~Distribution ~~p~~Providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to ~~d~~Distribution ~~p~~Providers that provide wires service for retail power marketers, these DPs were LSEs for that load prior to state retail access programs. In many instances, these ~~d~~Distribution ~~p~~Providers remain providers of last resort and must plan their system taking into consideration all load served over their wires, including retail access load.

The Order also provides that a ~~d~~Distribution ~~p~~Provider will not be registered based on the above criterion if it has transferred responsibility to another entity (that is appropriately registered) by written agreement.

NERC also stated that this approach ensures that all loads are represented in the planning and operation of the Bulk-Power System by the entity with the best information regarding those loads.

The scope of the review leading to Version 5.1 of the ~~Functional~~ Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.

[4] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

Version 5.1 does *not* contain changes to reflect these changes to the Registry Criteria, as follows:

- the problem and its solution relate to registration, not the tasks performed, and as such do not directly affect the Model; this is in keeping with the approach used for the Joint Registration Organization, which is defined for compliance purposes and not in the Model
- the present solution is a short-term one, with the longer-term solution yet to be defined.

-
  - ~~the present solution is a short-term one, with the longer-term solution yet to be defined.~~

11. Terminology Changes in Version 5

Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[5] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:

- Entity terminology
- Entity names
- Entity definitions.

Entity terminology

The term "responsible entity" in the Model has been changed to "functional entity".[6]

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the NERC Rules of Procedure and Glossary of Terms to consistently use the term "functional entity" when the reference is to the *class of entity* (e.g., BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[7]

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the function.
  - A conforming change would be required in the Glossary (which also uses Interchange Authority)
- Conforming changes would be required in other NERC documents.

[5] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial that is, not representing changes to essential content.

[6] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", i.e., all lower case, this usage has been adopted for version 5 of the Model.

[7] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.

Entity definitions

- The Model has been revised to define the various *functional entities*, not the *Functions* as at present, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The functional entity …"
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

The following table gives the Version 4 definitions, the Glossary definitions (April 20, 2009), and the Version 5 definitions (recommended for use in the Glossary.

Functional Entity Definitions:

Model Version 4, NERC Glossary and Model Version 5

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
Balancing Authority	**Balancing Authority**	**Balancing Authority**	
Integrates resource plans ahead of time, and maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.	The responsible entity that integrates resource ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.	The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency in real time.	Minor Glossary change needed.
Compliance Enforcement Authority	**Compliance Monitor**	**Compliance Enforcement Authority**	
Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.	The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the	Glossary needs to be updated

[8] For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functionFunctional entityFunctional Entity, not the functionFunction. For example, the Model has a definition for the Standards Development functionFunction, but the definition is shown below as applying to the Standards Developer *function**Functional entity**Functional Entity*.

[9] Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf

[10] These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
		standards.	
Distribution Provider	**Distribution Provider**	**Distribution Provider**	
Provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Glossary change needed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Generator Operator	**Generator Operator**	**Generator Operator**	
Operates generating unit(s) to provide real and reactive power.	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.	Minor Glossary change needed.
Generator Owner	**Generator Owner**	**Generator Owner**	
Owns and provides for maintenance of generating facilities.	Entity that owns and maintains generating units.	The functional entity that owns and maintains generating units.	Minor Glossary change needed.
Interchange Coordinator	**Interchange Authority**	**Interchange Coordinator**	
Ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Arranged Interchange between Balancing Authority Areas.	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Load-Serving Entity	**Load-Serving Entity**	**Load-Serving Entity**	
Secures capacity, energy and transmission services (including necessary	Secures energy and transmission service (and related Interconnected	The functional entity that secures energy and transmission services (and	Minor Glossary change needed.

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
reliability-related services) to serve the End-use Customer.	Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	reliability-related services) to serve the electrical demand and energy requirements of its end-use customers.	
Market Operator (Resource Integrator)	[not defined]	**Market Operator (Resource Integrator)**	
The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with commercial functions.		The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.	Term not used in Reliability Standards and therefore is not required in the Glossary..
Purchasing-Selling Entity	**Purchasing-Selling Entity**	**Purchasing-Selling Entity**	
Purchases or sells energy, capacity, and necessary reliability-related services as required.	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability-related services.	Glossary change needed – descriptive detail removed.
Planning Coordinator	**Planning Authority / Coordinator**	**Planning Coordinator**	
Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator area. It integrates and evaluates the plans from the Transmission Planners and Resource Planners within the Planning Coordinator area to ensure those plans meet the Reliability Standards.	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas	Minor Glossary changed needed.
Reliability Assurer	[not defined]	**Reliability Assurer**	
Monitors and evaluates the activities related to planning		The functional entity that monitors and evaluates the	Term not used in Reliability Standards and therefore is

VERSION 4[9]	GLOSSARY[9]	VERSION 5[10]	COMMENT
and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.		activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.	not required in the Glossary.
Reliability Coordinator	**Reliability Coordinator**	**Reliability Coordinator**	
Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.	Glossary changed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Resource Planner	**Resource Planner**	**Resource Planner**	
Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy [of] specific loads (customer demand and energy requirements) within a Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.	Minor Glossary change needed.
Standards Developer	[not defined]	**Standards Developer**	

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
Develops and maintains Reliability Standards to ensure the reliability of the bulk power system.		The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.	Term not used in Reliability Standards and therefore is not required in the Glossary.
Transmission Operator	**Transmission Operator**	**Transmission Operator**	
Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Transmission Owner	**Transmission Owner**	**Transmission Owner**	
Owns and provides for the maintenance of transmission facilities.	The entity that owns and maintains transmission facilities.	The functional entity that owns and maintains transmission facilities.	Minor Glossary change needed.
Transmission Planner	**Transmission Planner**	**Transmission Planner**	
Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area as well as coordinating with the plans from adjacent and overlapping Transmission Planners and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner Area.	Minor Glossary change needed.
Transmission Service Provider	**Transmission Service Provider**	**Transmission Service Provider**	
Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	Minor Glossary change needed.

~~12.~~11.

Reliability Areas and Boundaries

Assets versus Geography as the Basis for Defining Areas and Boundaries

It is useful for organizations that are ~~f~~Functional Ee~~e~~ntities to specify an associated Area, which defines the portion of the ~~Bulk Electric System~~BES within which their ~~f~~Functional ~~e~~Entity status applies. Moreover, by reviewing all of the Areas for a particular ~~f~~Functional ~~e~~Entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.

The ~~Functional~~ Model building block for defining boundaries and Areas for the ~~f~~Functional entities that operate and plan the B~~ulk~~ E~~lectric~~ S~~ystem~~ is electrical, namely the individual B~~ulk~~ E~~lectric~~ S~~ystem~~ asset. That is, the building blocks are the individual transmission, generation and customer equipment assets that collectively constitute the B~~ulk~~ E~~lectric~~ S~~ystem~~. This enables any given B~~ulk~~ E~~lectric~~ S~~ystem~~ asset to be associated with a single organization, with respect to any particular ~~f~~Functional ~~e~~Entity. This will therefore provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset, where the specific responsibility is to be established in NERC's registration, certification and compliance processes.

It is noted that a geographic definition is not adequate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific ~~Bulk Electric System~~BES assets provides an adequate basis for defining Areas/boundaries.

The NERC Rules of Procedure specify area relationships among ~~f~~Functional Ee~~e~~ntities, excerpted as follows:

> 2.2 Regional entities shall verify that all balancing authorities and transmission operators are under the responsibility of one and only one reliability coordinator.
>
> 2.3 Regional entities shall verify that all transmission elements of the bulk power system operated within their geographic boundaries are under the authority and control of one and only one transmission planner, planning authority, transmission owner, and transmission operator.
>
> 2.4 Regional entities shall verify that all loads and generation sources within their geographic boundaries are under the authority and control of one and only one balancing authority.
>
> 2.5 Regional entities shall verify that no geographical or electrical areas of the bulk power system within their boundaries have duplication of coverage or are lacking an entity to perform required duties and tasks as identified in the ~~r~~Reliability ~~s~~Standards.

Size Considerations Relating to Area

The ~~Functional~~ Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the ~~Responsible~~ Functional Entity for a particular Function by virtue of performing the Function's ~~T~~tasks.

Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.

~~13.~~12. Generating versus Transmission Assets

The Model does not attempt to define the boundary between generating and transmission ~~f~~Facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.

From the perspective of the Model, for a ~~f~~Facility that is determined to be a generating ~~f~~Facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a ~~f~~Facility that is determined to be a transmission ~~f~~Facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.

It is recognized that an owner may not be the operator of its ~~f~~Facility, as a result of delegating the operating of the ~~f~~Facility to another party through an ~~a~~Agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a ~~f~~Functional ~~e~~Entity.

~~14.~~13. Roles in Load Curtailment

This section discusses the roles of the various ~~f~~Functional E~~e~~ntities that may be involved in load ~~c~~Curtailment. These entities include: Reliability Coordinator, Balancing Authority(ies), Transmission Operator, Distribution Provider and Load-Serving Entity.

Types of Load Curtailment

There are two general types of load curtailment — voluntary and non-voluntary.

A. Voluntary Load Curtailment

Voluntary load curtailments are usually arranged ahead of real time under some form of agreements — market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority(ies) in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.

Voluntary load curtailment based on pricing structure need not be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since ~~e~~End-use ~~c~~Customers are involved in the decision-making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the ~~e~~End-use ~~c~~Customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority(ies) and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority(ies) area or potential overload on the Distribution Provider system.

B. Non-Voluntary Load Curtailment (Shedding)

Non-voluntary load ~~c~~Curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedance of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the ~~e~~End-use ~~c~~Customers and communication via the Load-Serving Entity is usually bypassed.

Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of underfrequency or undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority(ies), or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.

Role of ~~Responsible~~ Functional Entities in Load Curtailment

Reliability Coordinator

The Reliability Coordinator maintains Real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority(ies) and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority(ies) cannot achieve resource-demand balance.

When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.

Balancing Authority(ies)

When a Balancing Authority(ies) anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority(ies) may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority(ies) will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority(ies) may direct non-voluntary load ~~e~~Curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.

Transmission Operator

The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.

Distribution Provider

The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority(ies) and Transmission Operator.

However, the Distribution Provider may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the ~~e~~End-use ~~e~~Customers. When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.

Load-Serving Entity

The Load-Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with

eEnd-use eCustomers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.

For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority(ies) or Distribution Provider to communicate its curtailment requests to the eEnd-use eCustomers.

For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make reasonable efforts to arrange (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.

The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate eEnd-use eCustomers, thereby increasing the effectiveness of voluntary load curtailment. In some jurisdictions, it appears that the “wires” entity, i.e., the Distribution Provider, that performs these Ttask. However, from a fFunctional Mmodel viewpoint, it is the Load-Serving Entity fFunction within that Distribution Provider organization that performs this task.

~~15.~~14. History of Revisions

Version 1
Version 1 of the Model was approved in February 2002.

Version 2
Version 2 of the Model[11] was approved Feb. 10, 2004.

Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the ~~T~~task), and Transmission Operator as the Responsible Entity for those ~~T~~tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.

The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.

Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (: Planning Authority(ies), Transmission Planner and Resource Planner).

Version 3
Version 3 of the Model was approved February 13, 2007.[12] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable ~~r~~Reliability ~~s~~Standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[13] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.

The changes introduced in Version 3 included:

- The Reliability Authority(ies) entity name was changed to Reliability Coordinator, for consistency with terminology used in ~~r~~Reliability ~~s~~Standards.
- Changes were made to more clearly define the Transmission Operations ~~T~~tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Authority(ies)~~Coordinator~~ to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling

[11] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.
[12] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.
[13] Final Report of the Functional Model — Reliability Standards Coordination Task Force (**"**FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.

- The Planning Authority(ies) was renamed the Planning Coordinator
- The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.
- It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection of ~~Bulk Electric System~~BES assets associated with the entity, that is, that area was defined electrically, not geographically.

Version 4
Version 4 included the following changes from Version 3:

- The names Regional Reliability Assurance / Regional Reliability Organization ~~-~~were changed to Reliability Assurance / Reliability Assurer.

  The name changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the ~~f~~Functional ~~e~~Entity need not be a Regional Entity.

- The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.

  The changes were judged to better reflect the strong role of compliance in the ERO regime.

- The wording was changed in a number of instances to ensure that the Model's ~~T~~tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in ~~r~~Reliability ~~s~~Standards and NERC processes, not in the Model.

- For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" were changed in Version 4 to simply "ensures".

- It was clarified that the Generator Owner and Transmission Owner provide for the maintenance of their respective assets.

  This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.

Version 5
Version 5 introduced the following changes:

Entity name

- Interchange Authority(ies) has been changed to Interchange Coordinator~~-~~. Also incorporated are the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.

Terminology
The term "responsible entity" in the Model has been changed to "~~f~~Functional ~~e~~Entity".

  - The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of task,

but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.

- The Model uses the term ~~f~~Functional ~~e~~Entity to apply to a *class of entity*, such as a Balancing Authority(ies), and makes no reference to the *specific organizations* that register as ~~f~~Functional ~~e~~Entities.
- Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the ~~Functional~~ Model, the NERC Rules of Procedure and Glossary of Terms.

- Entity definitions
- The Model has been revised to define the various *F~~f~~unctional ~~e~~Entities*, not the *~~f~~Functions*, consistent with the approach used in the Glossary and standards.
- The ~~f~~Functional ~~e~~Entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The ~~f~~Functional ~~e~~Entity that…"
  - Each definition is single sentence, limited to a simple statement of the nature of the task performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

Version 5.1

Version 5.1 incorporated the following changes:

Entity name

- Interchange Coordinator has been changed to Interchange Authority(ies) to be aligned with NERC Glossary of Terms

Terminology

- The Model has been revised to define the various *Functional Entities*, in alignment with the NERC Glossary of Terms.
- Where appropriate, a term that is capitalized in the NERC Glossary of Terms has been capitalized in the Model and Technical Document

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:	August 7, 2018		
SAR Requester			
Name:	Standards Efficiency Review (SER) Team (Charles Rogers, Michael Cruz-Montes, Latroy Brumfield)		
Organization:	Standards Efficiency Review (SER) Team		
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?):			
Many NERC Reliability Standards have been mandatory and enforceable for over 10 years in North America, Phase 1 of the Standards Efficiency Review (SER) project seeks to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Phase 1 of this project reduces the number of mandatory and enforceable requirements with which registered entities must comply.			

Project Scope (Define the parameters of the proposed project):
The Standards Efficiency Review (SER) team used a risk-based approach to evaluate the reliability benefit of each requirement. Based on its analyses, the SER team is recommending the requirements listed below be retired. • BAL-005-1 R4, R6 • COM-002-4 R2 • EOP-005-3 R8 • EOP-006-3 R7 • FAC-008-3 R7, R8 • FAC-013-2 R1, R2, R4, R5, R6 (All) • INT-004-3.1 R1, R2, R3 (All) • INT-006-4 R3.1, R4, R5 • INT-009-2.1 R2 • INT-010-2.1 R1, R2, R3 (All) • IRO-002-5 R1, R4, R6 • IRO-008-2 R6 • IRO-014-3 R3 • IRO-017-1 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 (All) • 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) • PRC-004-5(i) R4 • PRC-015-1 R1, R2, R3 (All) • PRC-018-1 R1, R2, R3, R4, R5, R6 (All) • 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):

In Phase 1 of the Standards Efficiency Review (SER) project, three SER teams [Real-time Operations (RT), Long-term Planning (LT), and Operations Planning (OP)] evaluated each requirement in the body of NERC Reliability Standards for unconditional retirement i.e. these requirements may be retired without any modifications to other standards or requirements. The observations/rationales for retiring the requirements (identified in the Project Scope above) are listed below.

BAL-005-1 R4, R6 (RT)
The reliability objective of this requirement is duplicative of TOP-010-1(i) R2.

The Balancing Authority is already required by TOP-010-1(i) R2 to have an Operating Process/Procedure to address quality of Real-time data (including 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 in Reliability Standard PER-005-2. Issuing and receiving Operating Instructions according to a company's specific communications protocols is a fundamental Real-time reliability-related task and would be included in an entity's PER-005-2 training program to ensure System Operators are competent to perform the activities necessary for compliance with COM-002-4 R4 – R7. Additionally, Communication Methods (e.g. Three-Part Communications) is part of the knowledge content expected to be performed by all System Operators for the Certififcation Examination.

EOP-005-3 R8 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task

[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.

and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

EOP-006-3 R7 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

FAC-008-3 R7, R8 (OP)
These requirements are duplicative of the data provision standards MOD-32-1, IRO-010-2, and TOP-003-3.

In MOD-032-1 R1, the PC and TP develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the TO and GO provide power capabilities data in item 3 and facility ratings data in items 3f, 4c, 6g in the steady-state column of Attachment 1 as requested by the TP or PC.

IRO-010-2 R1 and TOP-003-3 R1 require the RC and TOP to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2 R3 and TOP-003-3 R5 require the TO and GO to respond to the RC's and TOP's requests.

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 acceptable system performance is.
- 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.
- Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness.

Additionally, the proposed retirement of FAC-013 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity with some entities not having a benefit for the assessment it at all. 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 and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered function. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of the NAESB WEQ Business Practice Standards, specifically covered in existing NAESB WEQ-004-1 and WEQ-004-5, and in proposed NAESB WEQ-004-1.8. Additionally, the NERC Independent Expert Review Panel concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R2 (RT and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered entity. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of a currently proposed revision to the NAESB WEQ Business Practice Standards. The language in R2, requiring Confirmed Interchange associated with Dynamic Schedules or Pseudo-Ties being updated for future hours when any of the three conditions cited in the requirement occur, is contained almost verbatim in the proposed NAESB WEQ-004-23. Additionally, the Independent Expert Review Team concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R3 (OP)
This requirement qualifies for Paragraph 81 retirement as it only obligates entities to register information with an entity, which the failure to do so would create no discernable reliability impact. The standard states the purpose of the requirement is allow for pseudo-tie coordination, which is already guided and more clearly explained within the NERC Pseudo-Tie Coordination Reference Document. Reliability Coordinator visibility to Pseudo-Ties is provided under existing NERC Standard IRO-010-2 Requirement R2. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-006-4 R3.1 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this

requirement. 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.

INT-006-4 R4 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.3.1 and Section 1.3, and is not a reliability-related task performed by a NERC registered entity.

INT-006-4 R5 (RT)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.4, and is not a reliability-related task performed by a NERC registered entity. 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 B7, as the requirement for Balancing Authorities to establish an agreed upon interchange metering source is redundant with approved NERC Reliability Standard BAL-005-1, R7.

INT-010-2.1 R1, R3 (RT)
These requirements satisfy Paragraph 81 Criteria 'B6 – Commercial or Business Practice' and 'B7 – Redundant' because more stringent requirement(s) that meet the objectives are already included in WEQ-004-1 of the NAESB WEQ Business Practice Standards. In the absence of these requirements, all Interchange would have an RFI submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of an RFI after Interchange has begun is for commercial purposes rather than reliability issues. The requirement to submit an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1 R2 (RT)
This requirement satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice' and 'B7 – Redundant' because more stringent tagging requirement(s) that meet the objectives are already included in WEQ-004-8 of the NAESB WEQ Business Practice Standards. In the absence of this requirement, all Reliability Adjustment Arranged Interchange would have a modification submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of a modification to a RFI after the modification has begun is for commercial purposes rather than reliability issues. The requirement to modify an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5 R1 (OP)

The requirement is 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 R3 in IRO-010-2. 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 needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature.

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

IRO-002-5 R6 (RT)
This requirement to have monitoring systems is unnecessary because IRO-002-5 R5 requires the monitoring of the systems which pre-supposes the ability (tools) to do so.

IRO-008-2 R6 (RT)
There is a potential for this requirement to become purely administrative in nature and not provide any reliability benefits. An Operating Plan required by IRO-014-3 R1, Part 1.1. or IRO-008-2 R5 would already include specific actions to notify impacted parties. The notifications for this requirement are after-the-fact and if the TOP, BA or other RC are a party to the implemented Operating Plan, then they would already be following the direction of the RC until notified.

IRO-014-3 R3 (RT)
The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (R1, Part 1.1).

IRO-017-1 R3 (LT)
The reliability objective of this requirement is duplicative of the reliability objective of TPL-001-4, R8 which mandates each Planning Coordinator and Transmission Planner distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners and to any other functional entity that has a reliability related need and submits a written request.

MOD-020-0 R1 (ALL) (LT)
This requirement is duplicative of the data provision requirements included in Reliability Standards MOD-031-2 and IRO-010-2.

MOD-020-0 R1 requires the Load-Serving Entity, Transmission Planner, and Resource Planner to provide Interruptible Demand and Direct Control Load Management upon requests by the Transmission Operators, Balancing Authorities, and Reliability Coordinators.

In MOD-031-2 R1.4.5 requires the Planning Coordinator or Balancing Authority to request, as necessary, total available peak hour forecast of controllable and dispatchable Demand Side Management from the applicable entities. R2 then requires 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, and R2 requires the RC to distribute its data specifications to all applicable entities. R3 then requires each applicable entity to respond to the request as specified.

PRC-004-5(i) R4 (OP)
The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with requirements R1 & R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a mis-operation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of R4 does not preclude the entity's responsibility to continue the investigation to identify the cause of mis-operation. However, it does alleviate the need to keep tracking documents for the sake of showing investigative actions.

PRC-015-1 R1, R2, R3 (All) (LT)
PRC-015-1 will be retired as it will be superseded by PRC-012-2. R1 requires the applicable entities to maintain a list of RAS which is an administrative requirement that does not contribute to the reliability of the BES. R2 references PRC-012-1 R1 which is not enforceable and will be superseded by PRC-012-2. Requirement R3 will be superseded by PRC-012-2. 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 have 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.

TOP-001-4 R16, R17 (OP)
These requirements 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 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. 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 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)
This requirement is duplicative of other SOL requirements. R2 is 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 (R12 and R14). R1 of TOP-001-4 requires the TOP to act and direct action to maintain reliability, including obtaining necessary reactive resources as described in VAR-001-4.2 R2.

VAR-001-4.2 R3 (OP)
This requirement is duplicative of TOP-001-4 requirements:

- 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 VAR-001-4.2 R3 to "operate or direct ... operation of devices to regulate ... voltage and reactive flow."

- The purpose of the actions taken under VAR-001-4.2, 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 is a Regional variance requirement applicable to WECC only. The continent-wide requirement VAR-002-4.1 R2.3 addresses the same reliability objective.

Additionally, the following Standards and Requirements were consolidated into MOD-001-2 in project 2012-05, which was filed for regulatory approval on February 10, 2014, and is still pending approval.

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (OP)
MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (OP)
MOD-008-1 R1, R2, R3, R4, R5 (OP)
MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (OP)
MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (OP)
MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (OP)

The February 10, 2014 petition notes that ATC/AFC are commercially-based values used to facilitate a market for unused transmission capacity in an open access environment and that the values do not directly control the operation of the BPS. It further acknowledges that TOPs are ultimately responsible for operating the grid in a reliable manner consistent with System Operating Limits, not ATC/AFC values. Nevertheless, the filing proposes MOD-001-2 for approval by FERC indicating ATC/AFC values have the potential to influence Real-time conditions on the Bulk-Power System and impact Real-time operations. Although, ATC/AFC values may have the potential to influence Real-Time conditions, there are a number of approved Reliability Standards that address potential impacts to Real-time operations and operation of the grid in a reliable manner consistent with System Operation Limits. This includes TOP Reliability Standard improvements that have been filed and approved since the MOD-001-2 filing in February 2014. NAESB may further address market issues associated with ATC/AFC, however these commercially-based values and market related issues should not be addressed through NERC Reliability standards.

Therefore, we recommend that NERC withdraw the February 10, 2014 petition related to MOD-001-2 and proceed with the retirement of the above listed MOD standards.

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.
☒	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

[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	
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	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ 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

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%			

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
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		

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
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		

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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		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements
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.

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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		

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
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		

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
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		

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
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		
600	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	9/5/2018	9/14/2018	Quorum: 75.59% Approval: 69.07%	Affirmative--9/5/18		

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

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

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1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11

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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

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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

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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

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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	

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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

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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

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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

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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	

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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	

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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

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139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13

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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

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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

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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

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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

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		– 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

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		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

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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

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		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

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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

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	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

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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

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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

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		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

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		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

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377	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Informal	8/10/18	9/6/18	Yes 9/6/18
378	Project 2018-02	Modifications to CIP-008 Cyber Security Incident Reporting SAR	CIP-008-5	Informal	8/10/18	9/10/18	Yes 9/10/18
379	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	7/30/18	9/14/18	Yes 9/14/18
380	Functional Model Advisory Group	Functional Model Advisory Group	Functional Model Advisory Group	Informal	8/3/18	9/19/18	Yes 9/17/18
381	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Informal	9/6/18	9/20/18	Yes 9/20/18
382	SER	Standard Efficiency Review	SAR	Formal	8/28/18	9/26/18	Yes 9/26/18

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

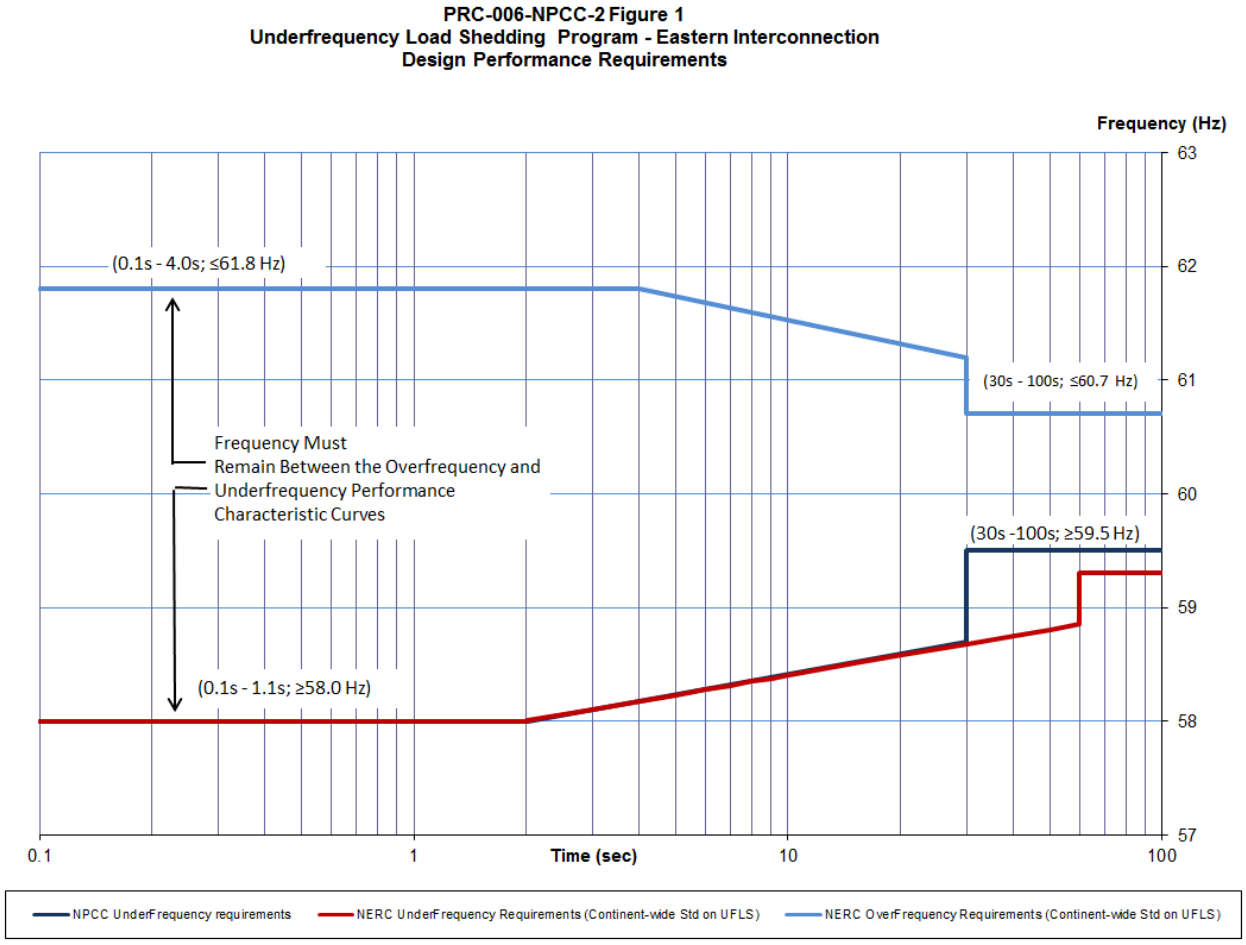
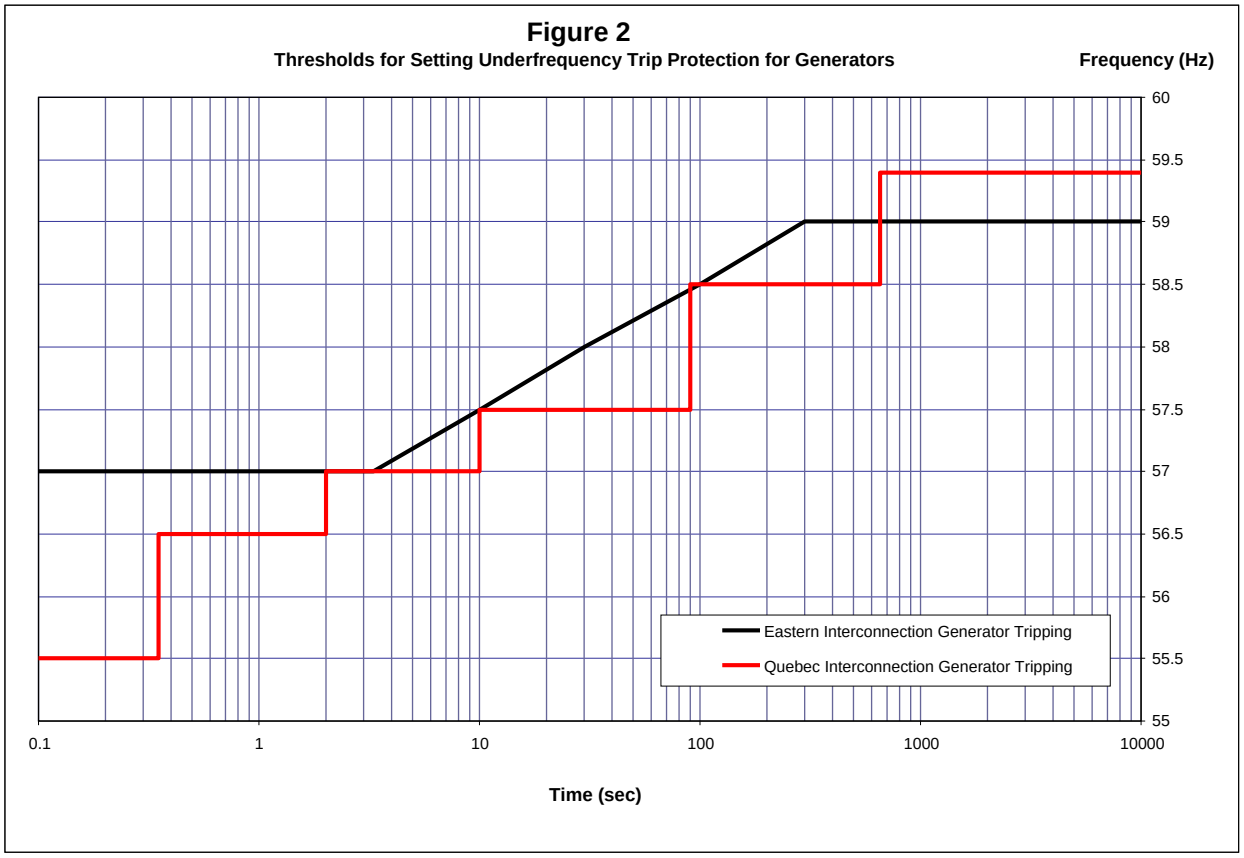


Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



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

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. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program as established by the Planning Coordinators.

   4.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program as established by the Planning Coordinators.

5. **Effective Date:**

   ~~Reference to~~See Implementation Plan.

B. Requirements

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. ~~Note that~~ 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 ~~greater~~ 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*

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- *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 Planning Coordinator shall, within 30 calendar days of completion of its UFLS system studies, identify to the Regional Entity all non-BES generation facilities, within its Planning Coordinator Area, that must not trip above the appropriate generator underfrequency trip threshold curve in Figure 2 in order to support UFLS program performance requirements. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*~~

~~**M3.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.~~

R34. 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 island identified per the NERC continent wide PRC-006 Standard on UFLS as follows:~~.~~ *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

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- **34.1.** 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 through 3; or~~,~~

- **34.2.** The program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS i~~I~~sland identified by the Planning Coordinator per 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~~ through~~ 3.

M34. 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 R34. (Attachment C Tables 1-3).

R54. ~~Each Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program, shall~~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 ~~Nn~~otify its Planning Coordinator within 30 calendar days ~~and shall~~: ~~notify its Planning Coordinator within the following 30 calendar days of identification and 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.

~~Notify its Planning Coordinator within 30 calendar days~~
~~Within the following 180 calendar days from notification of the Planning Coordinator, develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator; or~~

~~Within the following 180 calendar days from notification to the Planning Coordinator, 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 adjoining entities residing within the same island(s) identified by the Planning Coordinator in R2. ,The technical study shall also demonstrate coordination and coordination with other UFLS programs of adjoining Planning Coordinators.~~

~~of recognition~~

~~5.1. Within the following 180 calendar days of the identification, develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with the Planning Coordinator, and implement the Corrective Action Plan; or.~~

~~5.2. Within the following 90 calendar days, determine if tolerances can be met through adjustments and notify the Planning Coordinator~~Within the following 180 calendar days of the

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~~identification, 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. This technical study shall be coordinated with UFLS programs of adjoining entities, and shall be acceptable to the Planning Coordinator.~~

~~**5.3.** If adjustments are possible, make the adjustments within 180 calendar days after determining that adjustments are possible, and notify the Planning Coordinator when complete, or,~~

~~**5.4.** If adjustments are not possible then:~~

~~**5.4.1.** Each Distribution Provider or Transmission Owner subject to Attachment C, Table 1, shall within 180 calendar days, provide its Planning Coordinator with a technical study that demonstrates that the Distribution Provider's or Transmission Owner's specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the BES, or~~

~~**5.4.2.** Each Distribution Provider or Transmission Owner subject to Attachment C, Table 2 or Table 3, or in the Quebec Interconnection, shall within 90 calendar days, 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 the UFLS program.~~

M~~5~~4. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R~~4~~5.

> ~~**Rationale for Requirement R6:** Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.~~

~~**R6.** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms minimum time delay. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*~~

~~**M6.** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R6.~~

> **Rationale for Requirement R~~7~~5:** 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 uUnderfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the uUnderfrequency 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~~7~~. 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~~7~~. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R5~~7~~.

R6~~8~~. 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~~8~~. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R6~~8~~.

R7~~9~~. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6~~8~~ shall develop and submit an implementation plan with respect to inhibit threshold 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~~9~~. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R7~~9~~.

R8~~10~~. Each Distribution Provider and Transmission Owner shall implement the inhibit threshold ~~settings~~ provided by the Planning Coordinator in accordance with Requirement R6~~8~~ and based on the Planning Coordinator approved implementation plan in accordance with R7~~9~~.
[Violation Risk Factor: High] [Time Horizon: Operations Planning]

M8~~10~~. 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~~10~~.

Rationale for Requirement R9~~11~~: ~~It is recognized that, i~~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. This being said, entities are required by R11 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~~11~~. 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~~11~~. 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 ~~frequency set point, 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~~11~~.

R10~~2~~. Each Generator Owner shall 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 in Requirements R13~~5~~ and R16~~8~~. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long Term Planning]*

M10~~2~~. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R10~~2~~.

R11~~3~~. 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~~3~~. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R11~~3~~.

R12~~4~~. 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]*

~~R~~12.1 ~~12~~4.1. 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.

~~R~~12.2. ~~12~~4.2. 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 settings threshold curve in Figure 2.

M12~~4~~. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R12~~4~~.

R13~~5~~. For existing non-nuclear units in service prior to ~~the effective date~~July 1, 2015 ~~of this standard, as documented in accordance with Attachments A or B,~~ that have underfrequency protections

set to trip above the appropriate curve in Figure 2: [Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long Term Planning]

~~R~~1~~3~~5.1. Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

~~R~~1~~3~~5.2. 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.

~~R~~1~~3~~5.3. Each Planning Coordinator in Ontario, Québec and the Maritime Provinces ~~in accordance with Attachment A and each Generator Owner in the New England States and in New York State in accordance with Attachment B~~ 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.

~~R~~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.

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M1~~3~~5. Each Generator Owner with existing non-nuclear units in service prior to ~~the effective date of this Standard~~July 1, 2015 which have underfrequency tripping that is not compliant with Requirement R10 ~~2~~shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R1~~5~~3.

R1~~4~~6. 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 R1~~3~~5.3 for generating units in its respective NPCC area. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long Term Planning]*

M1~~4~~6. Each Planning Coordinator in Ontario, Quebec and the 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 R1~~4~~6.

R1~~5~~7. Each Generator Owner, Distribution Provider or Transmission Owner within the ~~Planning Coordinator area of ISO-NE~~ISO-NE Planning Coordinator area and in ~~or the New York~~NY-ISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R1~~3~~5.~~4~~3 for generating units in its respective NPCC area. *[Violation Risk Factor: ~~Medium~~High]*
[Time Horizon: Long Term Planning]

M1~~5~~7. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the ~~New York~~NY-ISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R1~~5~~7.

R1~~6~~8. 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 basis, shall: *[Violation Risk Factor: ~~Medium~~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.

~~**R16.1** Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.~~

~~**R16.2** Each Generator Owner of existing nuclear non-boiling water generating plants that cannot satisfy the condition of maximum 57.8 Hz imposed by R16.1., due to extenuating circumstances such as equipment limitations or design and licensing limitations, shall set the underfrequency protection to operate at the lowest frequency allowed by the existing limiting factor. Auxiliary power supplies located at the nuclear generating plants, driven by non-nuclear prime movers, that are connected to the grid only for the duration of testing, are considered non-nuclear units and are subject to compliance with the obligations spelled out in requirement R13.~~

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~~**R16.3** Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.~~

~~**R16.4** Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.~~

~~**168.1.** Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.~~

~~**168.2.** Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.~~

~~**168.3.** Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.~~

M168. Each Generator Owner of nuclear units that have ~~have been specifically identified by NPCC as having~~ 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 R168.

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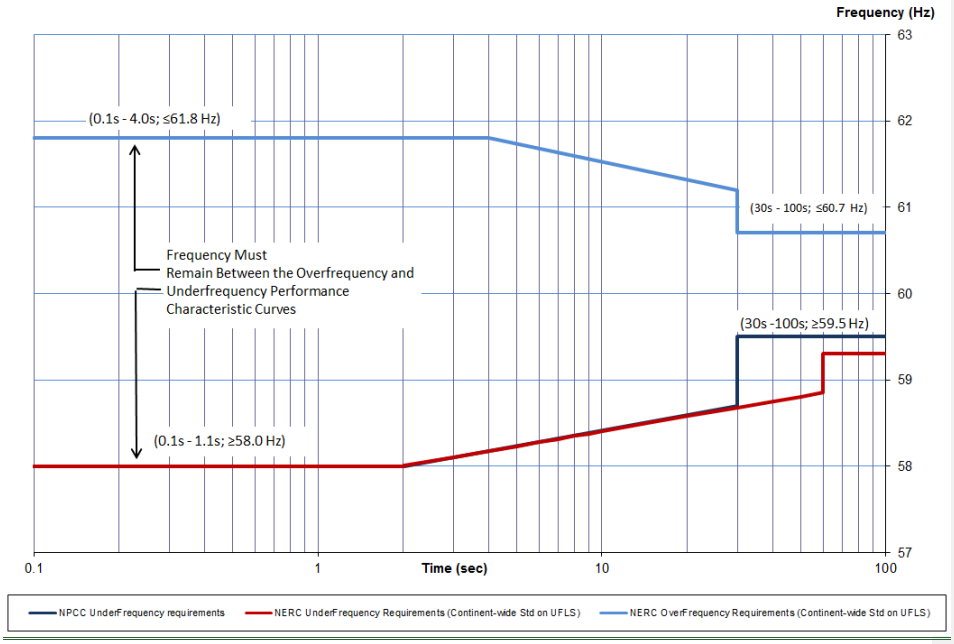
Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz
Design Performance Requirements

PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements



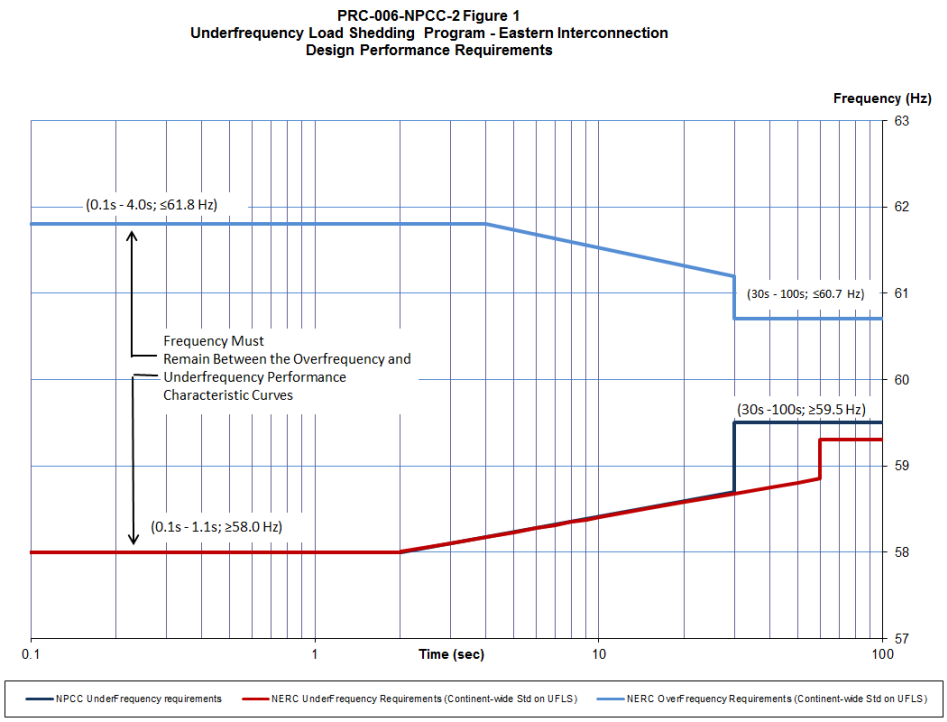
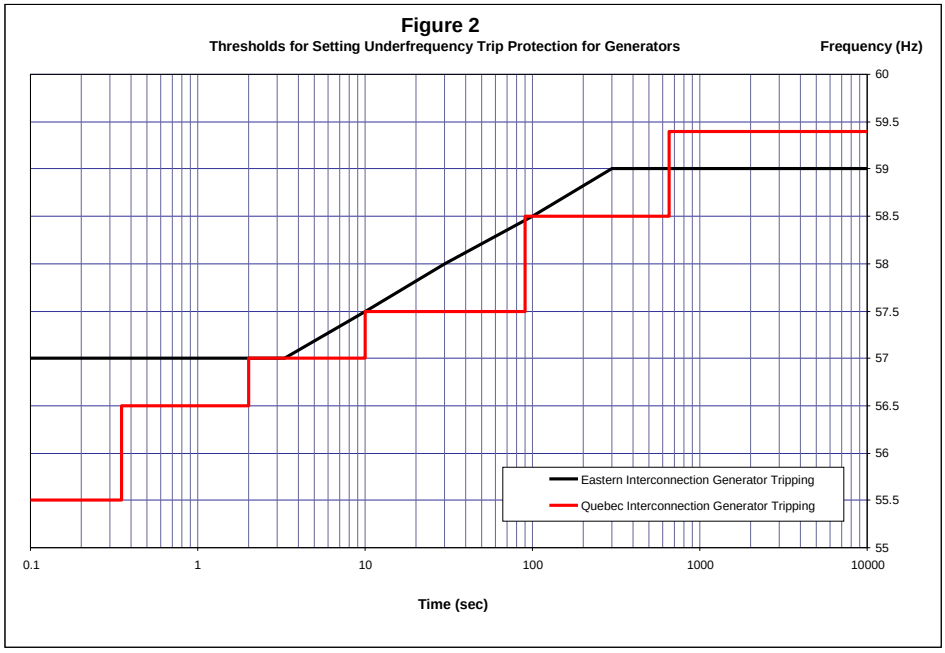


Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators

Figure 2



C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Northeast Power Coordinating Council~~PCC Compliance Committee~~

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~Not Applicable~~

~~1.3.~~1.2. ~~Data~~Evidence ~~-~~Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 2~~4~~, 3~~5~~, ~~4~~6, ~~5~~7, 8~~10~~, and 9~~11, and 12~~.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, ~~3, 6~~8, and 7~~9, 20, and 21~~.

~~The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.~~

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 1~~18, 22, and 23~~5.

The Generator Owner shall keep evidence for three calendar years for Measures 1~~0~~3, 1~~1~~4, 1~~5~~2, 1~~3~~6, and 1~~6~~9.

~~1.4.~~1.3. Compliance Monitoring and Assessment Processes

Compliance Audit~~Self-Certifications.~~

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints~~Spot Checking.~~

~~Compliance Audits.~~

~~Self-Reporting.~~

~~Compliance Violation Investigations.~~

~~Complaints.~~

~~**1.5. Additional Compliance Information**~~

~~None.~~

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	N/A	The Plannning 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 ~~The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.~~Coordinator provided 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 PRC 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 provided its UFLS island boundaries, as identified per the NERC PRC 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.~~The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS. within 60 calendar days following a request.~~

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~~R3~~	~~The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support UFLS program performance requirements, but did so more than 30 calendar daysand up to and including 40 days after completion of the system studies.~~	~~The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program performance requirements, but did so more than 40 days but less than calendar days but less than and including 50 days after completion of the system studies.~~	~~The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program performance requirements,, but did so more than 50 calendar days but less than and including 60 days after completion of the system studies.~~	~~The Planning Coordinator identified all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program performance requirements, but failed to inform the Regional Entity within 60 calendar days after completion of the system studies.~~ ~~OR~~ ~~The Planning Coordinator did not identify the BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to supportUFLS program performance requirements.~~	
R~~3~~4	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~~The Distribution Provider or Transmission Owner failed to implement the automatic UFLS program on an island basis as specified by Requirement R4, Part 4.1 or Part 4.2.~~	**Formatted:** Font: (Default) Times New Roman **Formatted:** Font: (Default) Times New Roman **Formatted:** Font: (Default) Times New Roman **Formatted:** Font: (Default) Times New Roman
R~~4~~5	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or	The Distribution Provider or Transmission Owner that cannot meet the	The Distribution Provider or Transmission Owner that cannot meet the	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or	**Formatted:** Font: (Default) Times New Roman **Formatted:** Font: (Default) Times New Roman **Formatted:** Font: (Default) Times New Roman

	number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for 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.~~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 ir 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.~~	tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for 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. ~~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 ir 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.~~	tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations but exceeded the permissible 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. ~~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 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.~~	number of stages and frequency set points specified in the UFLS Program failed to meet all of items in Requirement 5 within 60 calendar days of permissible time for each item. ~~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 calendar days of permissible time for each item.~~
~~**R6**~~	~~The Distribution Provider or Transmission Owner set less than 100% but more than (and including) 95% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.~~	~~The Distribution Provider or Transmission Owner set less than 95% but more than (and including) 90% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.~~	~~The Distribution Provider or Transmission Owner set less than 90% but more than (and including) 85% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.~~	~~The Distribution Provider or Transmission Owner set less than 85% ot its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.~~
R5~~7~~	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	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more	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

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	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 100% but more than (and including) 95% of relays within its region's UFLS program.~~	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 95% but more than (and including) 90% of relays within its region's UFLS program.~~	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 90% but more than (and including) 85% of relays within its region's UFLS program.~~	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~~8~~	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 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 40 calendar daysbut 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 provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 calendar daysbut 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 ~~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~~9~~	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~~	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~~	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~~	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request. ~~The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan~~

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	~~more than 90 calendar days and up to and including 100 calendar days following the request.~~	~~submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.~~	~~Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.~~	~~within 120 days following the request.~~
R~~8~~10	Implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 100% but more than (and including) 95% of UFLS relays.~~implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 100% but more than (and including) 95% of UFLS relays.~~	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.~~The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.~~	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.~~The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85 % of UFLS relays.~~	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.~~The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85 % of UFLS relays.~~
R~~9~~11	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~~	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	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	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.~~The Distribution Provider or Transmission~~

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	~~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.~~	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.~~	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.~~	~~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~~2~~	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. ~~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~~3~~	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	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	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	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.~~The Generator~~

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	request.~~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.~~	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.~~	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.~~	~~Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.~~
R1~~2~~4	N/A	N/A	The Generator Owner with a new generating unit, or an existing 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.~~The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%:~~ ~~Did not: fulfill the obligation of Requirement R14; Part 14.1~~ ~~OR~~ ~~Did not fulfill the obligation of Requirement R14, Part 14.2.~~	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%, did not fulfill the obligations of Requirement R12, Part 12.1 and Part 12.2. ~~The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%, did not fulfill the obligations of Requirement R15, Part 15.1 and Part 15.2.~~
R1~~3~~5	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 Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified	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

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		the Planning Coordinatoras specified in Requirement R13, Part 13.2.~~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 Coordinator.as specified in Requirement R15, Part 15.2.~~	in Requirement 13, Part 13.1 ~~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 Requirment 15, Part 15.1~~	to arrange for compensatory load shedding as specified in Requirement R13, Part 13.3.~~The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner in the New England States and in New York State failed to arrange for compensatory load shedding as specified in Requirement R15, Part 15.3.~~
R1~~6~~	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.~~The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.~~
R1~~7~~	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.~~The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.~~
R1~~8~~	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	The Generator Owner: Failed to set the underfrequency protection as specified	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

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		settings to the Planning Coordinator as specified in Requirement R16, Part 16.3.~~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 Coordinator as specified in Requirement R18, Part 18.3.~~	in Requirement R16; Part 16.1 OR Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.~~The Generator Owner:~~ ~~Failed to set the underfrequency protection as specified in Requirement R18; Part 18.1~~ ~~OR~~ ~~Failed to set the frequency trip setting upper tolerance as specified in Requirement R18, Part 18.2.~~	~~The Generator Owner did not fulfill the obligations of Requirement R18, Part 18.1 and Part 18.2.~~

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, as identified in Requirement R1

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.

~~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, in service prior to the effective date of Version 1 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-1 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.

~~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 in service prior to the effective date of Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate the Generator Owner's 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 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

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 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

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.

PRC-006-NPCC-1 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:			
Frequency Threshold (Hz)	Total Nominal Operating Time (s)[2]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5

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.

59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	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)	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	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

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)	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	0.30	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.

~~Guidelines and Technical Basis:~~

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~~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~~**Rationale Box:**

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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

A. Introduction

~~2.1~~1. Title: **Automatic Underfrequency Load Shedding**

~~2.2~~2. Number: PRC-006-NPCC-2~~1~~

~~2.3~~**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~~To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics~~.

~~2.4~~4. Applicability:

~~a.~~**4.1.** Generator Owner

~~b.~~**4.2.** Planning Coordinator

~~c.~~**4.3.** 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~~Distribution Provider~~

~~d.~~**4.4.** 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~~Transmission Owner~~

~~2.5~~5. Effective Date:

See Implementation Plan ~~For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:~~

~~The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.~~

~~For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:~~

~~All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017~~.

B. Requirements

Rationale for Requirement R1: Figure 1 of this document shows the NPCC

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~~Adopted by Board of Trustees: February 9, 2012~~

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).

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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.

~~**R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

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

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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

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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.

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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.

~~**R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]**~~

~~**R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]**~~

~~**R4 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 for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.**~~
~~**[Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

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5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 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.

R6. Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7. Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8. Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (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]

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R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

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R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 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 coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

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R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

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R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 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 settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

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16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

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16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 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 R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

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R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for

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~~generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~R19. 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 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

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~~19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.~~

~~19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.~~

~~19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.~~

~~R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

~~20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.~~

~~20.2 The buses at which the Load is modeled in the NPCC library power flow case.~~

~~20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.~~

~~20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.~~

~~20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.~~

~~**R21. Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R22. Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R23. Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]**~~

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]*

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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.

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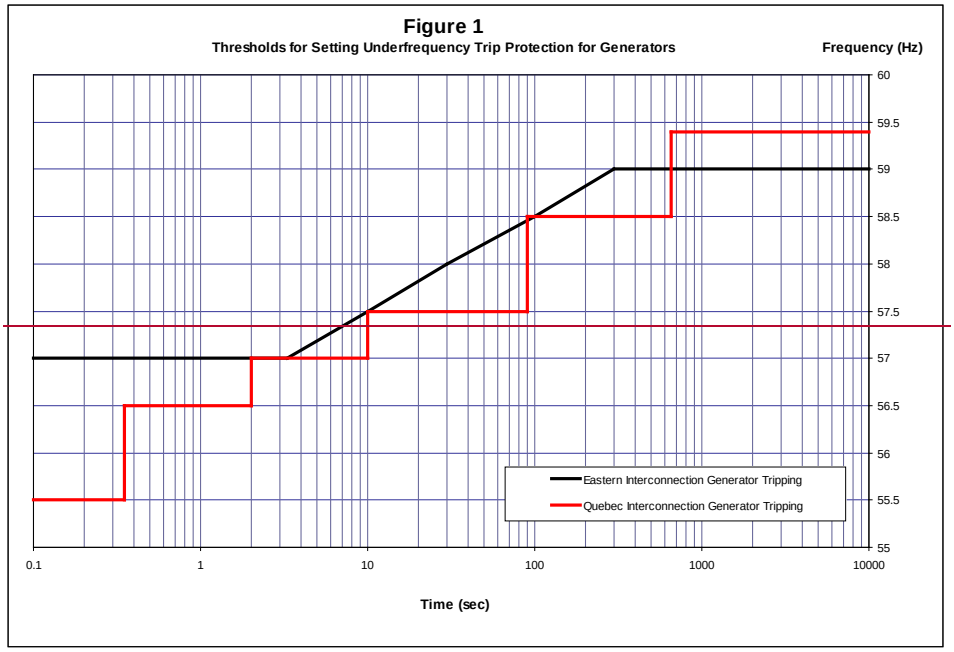

Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz Design Performance Requirements

PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements

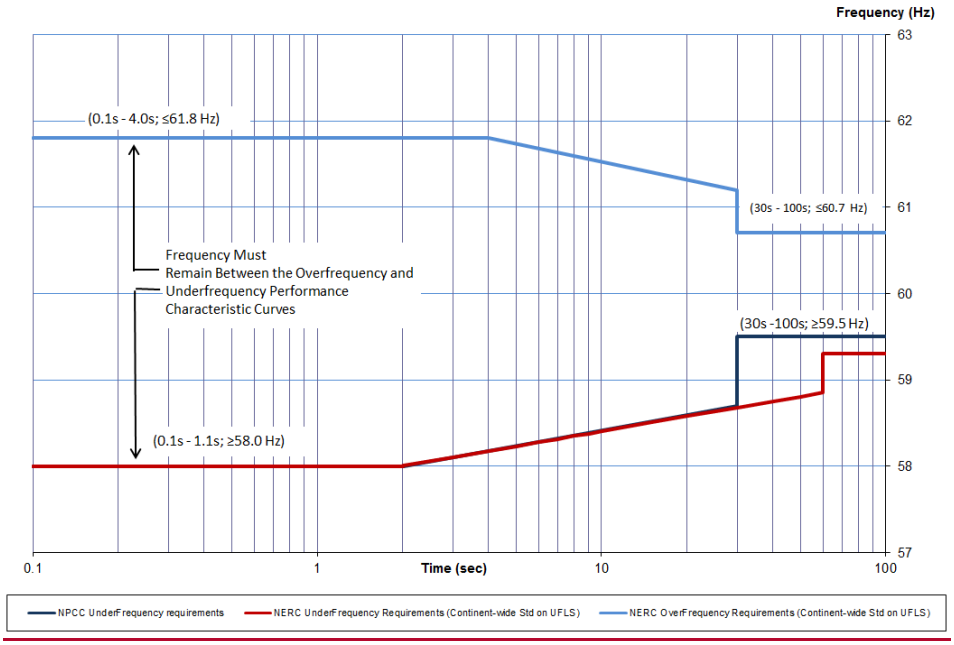

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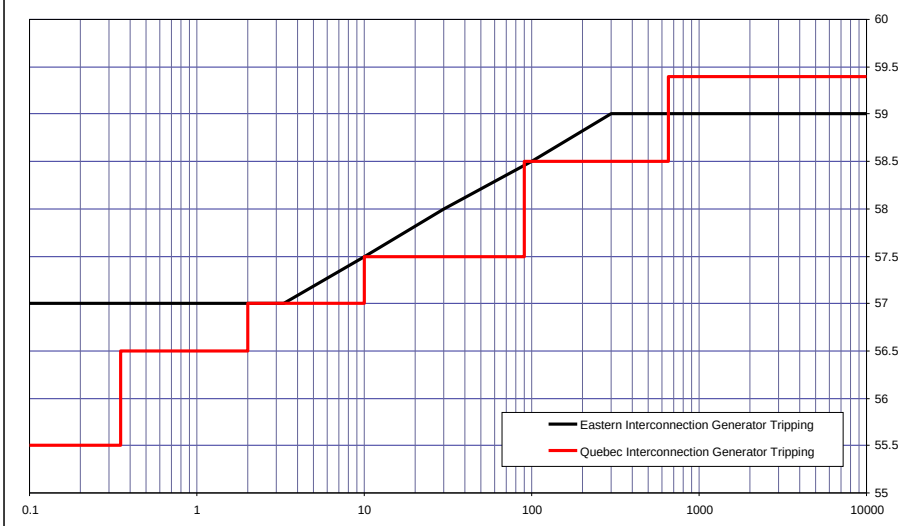
Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators

Figure 2



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C. Measures

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.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 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, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 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 frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D.C. Compliance

1.11. Compliance Monitoring Process

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a.1.1. Compliance Enforcement Authority

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Northeast Power Coordinating CouncilPCC Compliance Committee

a. **Compliance Monitoring Period and Reset Time Frame**

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Not Applicable

b.1.2. DataEvidence Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 24, 35, 46, 57, 810, and 119, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, 3, 86, and 79, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

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The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 1~~8~~5~~, 22, and 23~~.

The Generator Owner shall keep evidence for three calendar years for Measures 10~~3~~, 11~~4~~, 12~~5~~, 13~~6~~, and 16~~9~~.

~~c.~~1.3.Compliance Monitoring and Assessment Processes

Com~~Self-Certifications.~~

~~Spot Checking.~~

~~Compliance Audits.~~

~~Self-Reporting.~~

~~Compliance Violation Investigations.~~

~~Complaints.~~pliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

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~~**d. Additional Compliance Information**~~

~~None.~~

~~1.2~~1. Violation Severity Levels

Requirement	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	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	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	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

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	Load required to be shed at each stage	required to be shed at each stage m	Load required to be shed at each stage.	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 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.	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 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.	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 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.	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 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	The Planning Coordinator provided to a Transmission Owner	The Planning Coordinator provided to a Transmission	The Planning Coordinator failed to provide to a

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	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.	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.	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.	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 less than 100% but more than (and including) 95% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.

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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	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days

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	days and less than (and including) 55 calendar days of the Planning Coordinator's request.	days and less than (and including) 65 calendar days of the Planning Coordinator's request.	days and less than (and including) 75 calendar days of the Planning Coordinator's request.	of the Planning Coordinator's request.
R12	N/A	N/A	The Generator Owner with a new generating unit, or an existing 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.	The Generator Owner with a new generating unit, or an existing generator increasing its net 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

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				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 Coordinator as specified in Requirement R16, Part 16.3.	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R16; Part 16.1 OR Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

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PRC-006-NPCC-1 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 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 1. 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 islands identified in Requirement R1 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~~The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. 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, as identified in Requirement R1

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:

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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~~Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding~~.

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2.2 In Ontario and in the Maritime provinces, ~~T~~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~~.~~.

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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~~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 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 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 1~~.

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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~~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~~.

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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

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of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility~~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-1 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~~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 1 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~~The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. 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~~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 1, 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

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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~~In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, 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~~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~~.

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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 ~~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~~.

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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~~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~~.

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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~~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~~.

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PRC-006-NPCC-1 Attachment C

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UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	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
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	– 31.5

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UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	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	0.30	14-25	14-25
2	59.1	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.

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UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	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	0.30	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.

~~UFLS Table 4: Quebec Interconnection~~

	~~Rate~~	~~Frequency (Hz)~~	~~MW at peak (*Load must be fixed at all times when above 60% of peak load..)~~	~~Mvar at peak~~	~~Total Nominal Operating Time (s)~~ [2]
~~Threshold Stage 1~~	~~——~~	~~58.5~~	~~1000*~~	~~1000~~	~~0.30~~
~~Threshold Stage 2~~	~~——~~	~~58.0~~	~~800*~~	~~800~~	~~0.30~~
~~Threshold Stage 3~~	~~——~~	~~57.5~~	~~800~~	~~800~~	~~0.30~~
~~Threshold Stage 4~~	~~——~~	~~57.0~~	~~800~~	~~800~~	~~0.30~~
~~Threshold Stage 5 (anti-stall)~~	~~——~~	~~59.0~~	~~500~~	~~500~~	~~20.0~~
~~Slope Stage 1~~	~~-0.3 Hz/s~~	~~58.5~~	~~400~~	~~400~~	~~0.30~~
~~Slope Stage 2~~	~~-0.4 Hz/s~~	~~59.8~~	~~800*~~	~~800~~	~~0.30~~
~~Slope Stage 3~~	~~-0.6 Hz/s~~	~~59.8~~	~~800*~~	~~800~~	~~0.30~~
~~Slope Stage 4~~	~~-0.9 Hz/s~~	~~59.8~~	~~800~~	~~800~~	~~0.30~~

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	Minimum Relay Time	Total Nominal	Load Shed at Stage as % of	Cumulative Load Shed as

~~2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.~~

	(Hz)	Delay (s)	Operating Time (s)[2]	TO or DP Load	% 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

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. 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.

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.

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1	59.5	0.10	0.30	28 – 50	28 – 50

Rationale Box:

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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:

2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

- 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

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 1, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Informational Filing Regarding BAL-001-2, Docket No. RM14-10-000 (Errata to Include Attachment)

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this informational filing regarding Reliability Standard BAL-001-2 (Real Power Balancing Control Performance), as directed by the Federal Energy Regulatory Commission ("Commission") in Order No. 810.[1] Reliability Standard BAL-001-2 is intended to ensure that Interconnection frequency is maintained within predefined frequency limits and improved upon the prior version of the standard by adding a frequency component to the measurement of a Balancing Authority ("BA") Area Control Error ("ACE") called the BA ACE Limit ("BAAL").

In approving Reliability Standard BAL-001-2, the Commission directed NERC to submit an informational filing after implementation of the standard regarding potential impacts on System Operating Limit ("SOL") and Interconnection Reliability Operating Limit ("IROL") exceedances in the Western and Eastern Interconnections.[2] In particular, the Commission stated:

> The Commission adopts the NOPR proposal regarding NERC's submission of an informational filing. …. Further, we find that the informational filing should encompass both the Western and Eastern Interconnections, as there were concerns about possible increases of SOL/IROL exceedances in both Interconnections.
>
> ….Therefore, we direct NERC to make an informational filing 90 days after the end of the two-year period following implementation that includes an analysis of data (all relevant events or a representative sample) on whether experience with the Balancing Authority ACE Limit in the first two years after approval has seen ACE swings and

[1] *Real Power Balancing Control Performance Reliability Standard*, Order No. 810, 151 FERC ¶ 61,048, 80 Fed. Reg. 22,395 (2015) ("Order No. 810").

[2] SOL is the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. An IROL is a SOL that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk power system.

> unscheduled power flows or inadvertent interchange that could cause SOL/IROL exceedances. However, if it is evident that during this two-year period the issues discussed above are creating SOL/IROL exceedances NERC should provide that information to the Commission, together with appropriate recommendations for mitigation, as this information becomes available. Further, NERC should also make the underlying data available to Commission staff upon request.[3]

The attached report presents NERC's analysis regarding whether experience with the BAAL has resulted in ACE swings and unscheduled power flows or inadvertent interchange that could cause SOL/IROL exceedances. To complete this analysis, NERC evaluated trends in frequency trigger limit exceedances, unscheduled flow mitigation hours in the Western Interconnection, transmission loading relief procedures in the Eastern Interconnection, frequency performance, and inadvertent interchange. Based on this analysis, NERC concludes that the BAAL has not resulted in an increase in SOL/IROL exceedances.

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
Candice Castaneda

Counsel for North American Electric Reliability Corporation

cc: Official service list in Docket No. RM14-10-000

[3] Order No. 810, PP 36-38. The Commission also directed NERC to revise the definition of Reporting ACE, which NERC filed and the Commission approved in 2016. *See, North Am. Elec. Reliability Corp*., Docket No. RD16-7-000 (Letter Order June 23, 2016). This informational filing satisfies all outstanding directives in Order No. 810.

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 the above-referenced proceedings.

Dated at Washington, D.C. this 1st day of October, 2018.

/s/ Candice Castaneda

Candice Castaneda
Counsel for North American
Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Report on NERC Standard BAL-001-2

Informational Filing in Compliance with FERC Order 810

September 2018

RELIABILITY | ACCOUNTABILITY

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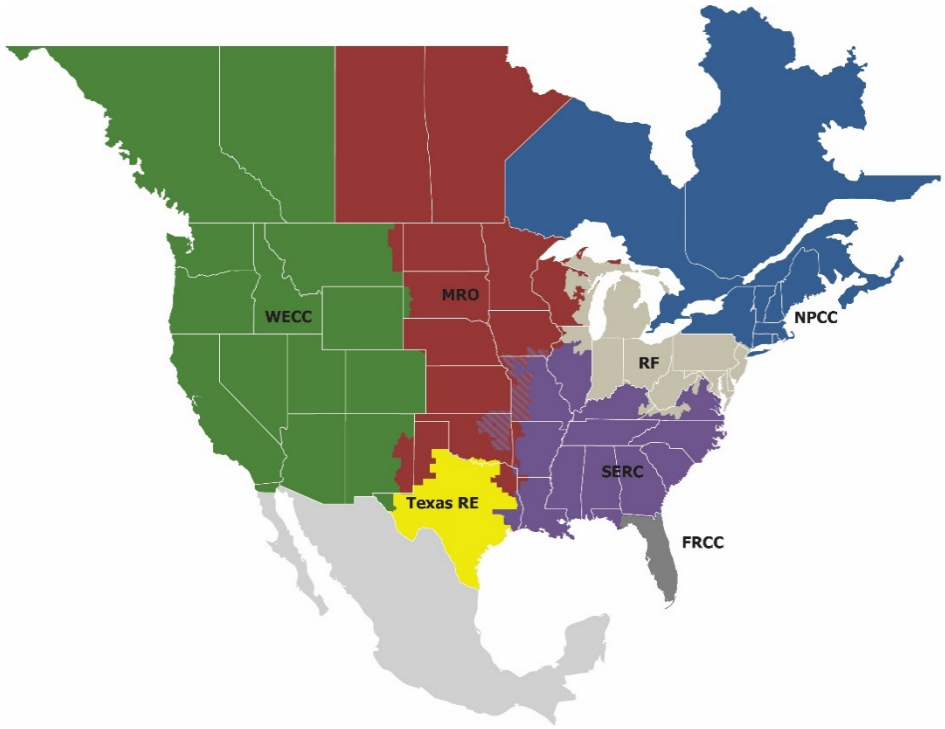
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven 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 seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

In Order No. 810, the Federal Energy Regulatory Commission (FERC) accepted Reliability Standard BAL-001-2 (Real Power Balancing Control Performance).[1] Reliability Standard BAL-001-2 is designed to ensure that applicable entities maintain system frequency within narrow bounds around a scheduled value. The standard improved reliability by adding a frequency component to the measurement of a Balancing Authority (BA) Area Control Error (ACE). In approving the standard, FERC also directed NERC to submit an informational filing pertaining to the standard's potential impact.[2]

In particular, FERC stated the following:

> "The Commission adopts the NOPR proposal regarding NERC's submission of an informational filing. …. Further, we find that the informational filing should encompass both the Western and Eastern Interconnections, as there were concerns about possible increases of SOL/IROL exceedances in both Interconnections.
>
> ….Therefore, we direct NERC to make an informational filing 90 days after the end of the two-year period following implementation that includes an analysis of data (all relevant events or a representative sample) on whether experience with the Balancing Authority ACE Limit in the first two years after approval has seen ACE swings and unscheduled power flows or inadvertent interchange that could cause SOL/IROL exceedances. However, if it is evident that during this two-year period the issues discussed above are creating SOL/IROL exceedances NERC should provide that information to the Commission, together with appropriate recommendations for mitigation, as this information becomes available. Further, NERC should also make the underlying data available to Commission staff upon request."[3]

This report provides NERC's analysis of the issues in accordance with FERC's directive.

Response to Order No. 810 Directive

Analysis of whether experience with the Balancing Authority ACE Limit (BAAL) in the first two years after approval of the standard has resulted in ACE swings and unscheduled power flows or inadvertent interchange that could cause SOL/IROL exceedances.

NERC concludes that, based on the analysis of data two years prior to and two years after the implementation of Reliability Standard BAL-001-2, the BAAL has not resulted in an increase in SOL/IROL exceedances. This analysis was based on NERC's evaluation of trends in frequency trigger limit exceedances, unscheduled flow mitigation hours (in the Western Interconnection), transmission loading relief procedures (in the Eastern Interconnection), frequency performance, and inadvertent interchange.

[1] Real Power Balancing Control Performance Reliability Standard, Order No. 810, 151 FERC ¶ 61,048 (2015).

[2] Order No. 810, at P 2 (directing, "analysis of data on whether experience with the Balancing Authority ACE Limit in the first two years after approval has seen ACE swings and inadvertent interchange and unscheduled power flows that could cause system operating limit (SOL) and interconnection reliability operating limit (IROL) exceedances."); *and id.*, n. 4–5 (noting, "Inadvertent interchange is '[t]he difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS).' NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) at 42." Adding, "Unscheduled power flows generally refers to power flows that result from the law of physics that causes power from a given source to flow over all possible paths to its destination.").

[3] Order No. 810, PP 36-38.

Introduction

The purpose of Reliability Standard BAL-001-2 is to assure reliability by maintaining Interconnection frequency within predefined frequency limits. This standard defined a new requirement, known as the BAAL, which replaced prior Reliability Standard BAL-001-1 Requirement R2 known as Control Performance Standard 2 (CPS2).[4] Compliance with the BAAL requires the BA to balance its resources and demand in real-time so that the clock-minute average of its reporting ACE does not exceed its clock-minute BAAL for more than 30 consecutive clock minutes.

The NERC Operating Committee (OC) endorsed a BAAL field trial that was subsequently approved by the NERC Standards Committee in June of 2005. The field trial began in the Eastern Interconnection in July of 2005. The Electric Reliability Council of Texas (ERCOT) Interconnection was added to the field trial in December of 2009, followed by the Western Interconnection in March of 2010, and the Québec Interconnection in September of 2010. The field trial ended for participating BAs upon the effective date of Reliability Standard BAL-001-2. Reliability Coordinators for all Interconnections monitored the performance of BAs participating in the field trial and held monthly field trial conference calls.

The following provide a background on the development of the BAAL, an overview of the BAAL field trial, and the analysis method used to satisfy the directive set forth in FERC Order 810.

Development of the BAAL

Control Performance Standard 1 (CPS1)

The foundation of the NERC Balancing Standards are the Real Power Balancing Control Performance requirements found in Reliability Standard BAL-001-2. The standard includes two requirements: CPS1 and BAAL. The predecessor to BAAL was CPS2. CPS1 assigns each Balancing Authority a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to Balancing Authority Frequency Bias. CPS1 measures ACE variability in combination with the Interconnection's frequency error in one-minute averages over a rolling one-year period and is derived from frequency-based statistical theory.

BAAL versus CPS2

CPS2 was designed to limit a BA's unscheduled power flows but was not designed to address Interconnection frequency. It measures the ability of a BA to maintain its 10-minute average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a BA needed to demonstrate that its average ACE value during a consecutive 10-minute period was within the L_{10} bound for at least 90 percent of all 10-minute periods over a one-month period. While this metric did require the BA to correct its ACE to not exceed specific bounds, it failed to recognize the positive or negative impact of that action on Interconnection frequency. The BAAL requirement provided dynamic limits that are BA and Interconnection specific. These ACE values are based on identified Interconnection Frequency Trigger Limits (FTLs) to ensure the Interconnection returns to a reliable state when an individual BA's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. The intent of BAAL was to replace and improve upon CPS2, which is not dynamic, is not based on Interconnection frequency and allows for a Balancing Authority's ACE value to be unbounded for a specific amount of time during a calendar month.

BAAL Analysis Methods

The purpose of this analysis is to use historic data to determine whether the implementation of BAAL control, in lieu of CPS2, has contributed in an increase in ACE swings, unscheduled power flows, or inadvertent interchange that could cause an increase in SOL/IROL exceedances. The time period evaluated includes two years prior to and two years after the implementation of BAAL. The analysis focuses on identifying trends in the number and duration of FTL

[4] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, available at http://www.nerc.com/files/Glossary_of_Terms.pdf.

exceedances, unscheduled flow (USF) mitigation hours in accordance with the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP), transmission loading relief (TLR) occurrences in accordance with Reliability Standard IRO-006-EAST-2, frequency performance, and inadvertent interchange. Particular attention is given to the multi-BA Western and Eastern Interconnections.

Frequency Trigger Limit (FTL) Exceedance Analysis

This analysis focuses on the one-minute frequency performance in the two multi-BA Interconnections, Western and Eastern, two years before and two years after the implementation of Reliability Standard BAL-001-2 as it relates to exceeding the FTLs. Under BAAL control, ACE swings could be more likely at the BA level when Interconnection frequency exceeds the FTLs due to BAAL allowing BA ACE to exceed the L10 boundaries used under its predecessor CPS2. The purpose of this analysis is to determine whether FTL exceedances have increased since the implementation of BAL-001-2 and BAAL.

Unscheduled Flow (USF) Mitigation and Transmission Loading Relief (TLR) Analysis

The WIUFMP is used to mitigate flows on Qualified Paths to reliable levels during real-time operations. Transmission Operators of Qualified Paths may use the WIUFMP to reduce flows on Qualified Paths. The purpose of this analysis is to determine whether conclusive evidence exists that transmission constraints and USF mitigation hours increased in the Western Interconnection as a direct result of BAAL implementation.

The NERC TLR Procedure is an Eastern-Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. The purpose of this analysis is to determine whether conclusive evidence exists that transmission constraints and TLR occurrences increased in the Eastern Interconnection as a direct result of BAAL implementation.

Frequency Performance and Inadvertent Interchange

Interconnection frequency can become more variable or noisy for a wide spectrum of issues, including congestion, multiple transmission line operations, generation losses, or general control issues. Adverse frequency control impacts due to the implementation of BAAL could be reflected in an increase in frequency variability, measured by RMS1. The purpose of this analysis is to determine whether conclusive evidence exists that frequency variability increased as a direct result of BAAL implementation.

Inadvertent Interchange is the difference between the BA's net actual interchange and its net scheduled interchange. BAs calculate and report Inadvertent Interchange for both On-Peak and Off-Peak periods. Adverse frequency control impacts due to the implementation of BAAL could be reflected in an increase in inadvertent interchange. The purpose of this analysis is to determine whether conclusive evidence exists that BA inadvertent interchange accumulations increased as a direct result of BAAL implementation.

Chapter 1: BAAL Field Trial

Below is a brief summary of observations, by Interconnection, during the BAAL Field Trial.

Eastern Interconnection

Number of Participating Balancing Authorities

Under a phased implementation, the field trial began in the Eastern Interconnection in July of 2005, and seven BAs that represented approximately 60 percent of the non-coincident peak demand in the Interconnection were operating under the field trial by the end of that year. After the initial field trial implementation, BAs were added to the field trial while others had been consolidated into larger BA Areas. This resulted in eleven BAs operating under the field trial, which represented approximately 75 percent of the non-coincident peak demand in the Interconnection.

Frequency Performance

There was an improvement in frequency performance in the Eastern Interconnection under the field trial, including a notable reduction in the total minutes of frequency beyond the FTL.

Unscheduled Flow Events

Throughout the duration of the field trial, no BA, Reliability Coordinator, or other participating reliability entity cited problems with unscheduled flows associated with operation of BAAL.

Western Interconnection

Number of Participating Balancing Authorities

The Western Interconnection began its participation in the BAAL field trial on March 1, 2010. Initially 26 out of 37 BA Areas participated in the field trial; another BA was later added, bringing the total number of BAs to 27 out of 38. The participating BA Areas represented approximately 90 percent of the non-coincident peak Demand in the Interconnection.

Frequency Performance

The Western Interconnection observed that the average one-minute frequency error increased from 10 mHz in 2009 to 18 mHz in 2013. The largest annual frequency error increase, from 10 mHz to 14 mHz, occurred between 2009 and 2010 when the field trial was first implemented. The Western Interconnection Epsilon1 frequency target is 22.8 mHz.

Unscheduled Flow Events

The hours of coordinated operations of the phase shifters increased during the field trial period. However, due to changing seasonal patterns, a changing resource mix, unusual operating conditions, and other events, it was not possible to conclusively associate the increased hours of phase shifter operations with the field trial. Additional information can be found in the WECC Performance Working Group report[5], approved by the WECC Operating Committee in March 2015.

Single BA Interconnections: ERCOT

Of the Interconnections in North America, two Interconnections have only one BA: ERCOT and Québec. ERCOT joined the BAAL field trial in December 2009, and Québec joined the field trial in September 2010. While ERCOT was already under a waiver from CPS2 since 2002, Québec chose not to request a waiver from CPS2 while operating under the field trial. As single BA Interconnections, ERCOT and Québec were affected differently than most BAs by the BAAL requirement.

[5] https://www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

Both single BA Interconnections found that currently implemented control methods were sufficient to easily meet the requirements specified by BAAL, and the BAs' only challenge was to implement the performance measurement to assure they could meet any audit and reporting requirement associated with BAAL.

Standard Drafting Team Conclusions

The BAL-001 Standard Drafting Team reached the following general conclusions from the field trial:[6]

- In the Eastern Interconnection, field trial participants observed an increase in System Operator understanding of Interconnection frequency control and improved timely response to significant ACE and frequency deviations. This led to a reduction in both the magnitude and duration of large frequency deviations on the Eastern Interconnection.
- One of the primary concerns of the standard drafting team when initiating the field trial was how replacement of CPS2 by BAAL would affect transmission constraints.
  - **Eastern Interconnection:** No case of an increase in the occurrence or magnitude of transmission constraints was identified and attributed to BAAL during the field trial.
  - **Western Interconnection:** During the field trial there were transmission constraints; however, there was no conclusive evidence that these transmission constraints were a direct result of BAAL.
- BAAL, in conjunction with NERC Standard BAL-003-1.1 Frequency Response and Frequency Bias Setting, meets the requirements set forth in Paragraph 355 of FERC Order No. 693.

[6] On the ERCOT and Hydro Québec single-BA interconnections, BAAL reduces to the FTL, and managing to the FTL has had no adverse impact on transmission reliability. While FTL replaces CPS2 in the Hydro Québec Interconnection, it is a whole additional constraint on the ERCOT Interconnection, which has operated since 2003 under a waiver from CPS2.

Chapter 2: FTL Exceedance Data

The BAAL method established FTLs that are used to determine each BA's BAAL control limits during both low and high frequency in accordance with Reliability Standard BAL-001-2. The FTL_{Low} is the Low Frequency Trigger Limit (calculated as Fs - 3Ɛ1) and FTL_{High} is the High Frequency Trigger Limit (calculated as Fs - 3Ɛ1) where Epsilon1 (Ɛ1) is the predefined targeted frequency boundary for each Interconnection.

This analysis focuses on the one-minute frequency performance in the two multi-BA Interconnections, Western and Eastern, two years before and two years after the implementation of Reliability Standard BAL-001-2 as it relates to exceeding the FTLs. Under BAAL control, ACE swings could be more likely at the BA level when Interconnection frequency exceeds the FTLs due to BAAL allowing BA ACE to exceed the L10 boundaries used under its predecessor CPS2. See Reliability Standard BAL-001-2 for more information on these calculation methods.[7] The purpose of this analysis is to determine whether FTL exceedances have increased since the implementation of BAL-001-2.

Note that two minor changes occurred in the calculation of FTL_{Low} and FTL_{High} and subsequently $BAAL_{Low}$ and $BAAL_{High}$ from the BAAL Field Trial methods to those of the BAL-001-2 standard that became effective in July 2016. The two changes are as follows and are reflected in the data analysis that follows in this chapter:

- The current standard uses scheduled frequency (Fs) in the calculations, taking into account the effect of time error corrections, whereas the field trial used only 60 Hz, and,
- The current standard uses 3Ɛ1 in the calculation of FTLs whereas the field trial used slightly smaller constants (i.e., 50 mHz in the EI and 68 mHz in the WI). This resulted in a slight increase of 4 mHz in both the FTL_{Low} and FTL_{High} for both the EI and WI).

Table 2.1 shows the FTL values for Eastern and Western Interconnection before and after the July 2016 implementation of BAAL.

Table 2.1: FTLs Before and After BAAL Implementation

Eastern Interconnection						
	Before July 2016			After July 2016		
	Fs = 60 Hz	Fs = 59.98 Hz	Fs = 60.02	Fs = 60 Hz	Fs = 59.98 Hz	Fs = 60.02
FTL_{High} (Hz)	60.05	60.05	60.05	60.054	60.034	60.074
FTL_{Low} (Hz)	59.95	59.95	59.95	59.946	59.926	59.966
Western Interconnection						
	Before July 2016			After July 2016		
	Fs = 60 Hz	Fs = 59.98 Hz	Fs = 60.02	Fs = 60 Hz	Fs = 59.98 Hz	Fs = 60.02
FTL_{High} (Hz)	60.068	60.068	60.068	60.0684	60.0484	60.0884
FTL_{Low} (Hz)	59.932	59.932	59.932	59.9316	59.9116	59.9516

Figure 2.1 (Western Interconnection FTL Exceedances) and **Figure 2.2** (Eastern Interconnection FTL Exceedances) show the monthly total number of FTL exceedance minutes and the number of monthly events where an FTL limit was exceeded by multiple consecutive minutes. FTL_{Low} and FTL_{High} exceedance data are shown on separate graphs. The exceedance events are categorized into four duration groups: events less than 10 minutes, events between 10 and 20 minutes, events between 20 and 30 minutes, and events greater than 30 minutes. One-minute frequency data was compiled for the time period from July 1, 2014, through June 30, 2018, reflecting two years before and two years

[7] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

after implementation of Reliability Standard BAL-001-2.[8] The red vertical line on the x-axis denotes the implementation of the standard on July 1, 2016.

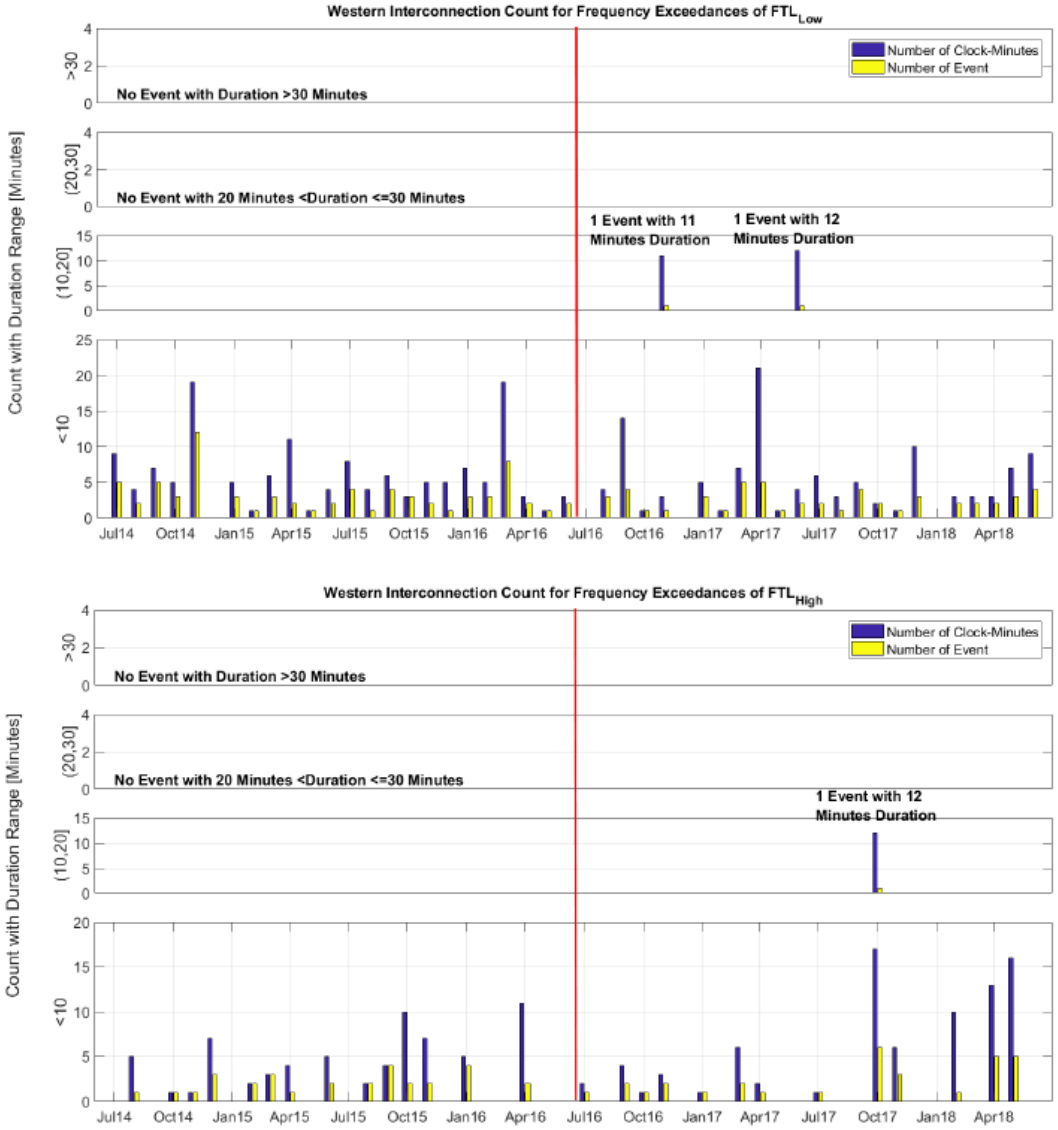


Figure 2.1: Western Interconnection FTL Exceedances

Western Interconnection observations for both total monthly FTL exceedance minutes and the number of events include the following:

- During November 2016, there is one FTL_{Low} event with an 11-minute duration that occurred when a market software issue resulted in undesirable unit commitment outputs from a Balancing Authority's security-constrained economic dispatch unit commitment software. This caused a reduction in generation output.[9]

[8] The data used in this chapter was compiled and analyzed by the Electric Power Group (EPG) using FNet frequency data from the University of Tennessee at Knoxville (UTK).

[9] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170401_Dispatched_Reduction_in_Generation_Output_Causes_Frequency_Deviation.pdf

- During June 2017, there is one FTL_{Low} event with a 12-minute duration that occurred when a high voltage DC transmission line tripped and resulted in remedial action scheme (RAS) operations.
- During October 2017, there is one FTL_{High} event with a 12-minute duration that occurred when the Western Interconnection separated between Canada and the United States following a 500 kV transmission line fault that resulted in RAS operations.
- There is no event with a duration greater than 20 minutes.

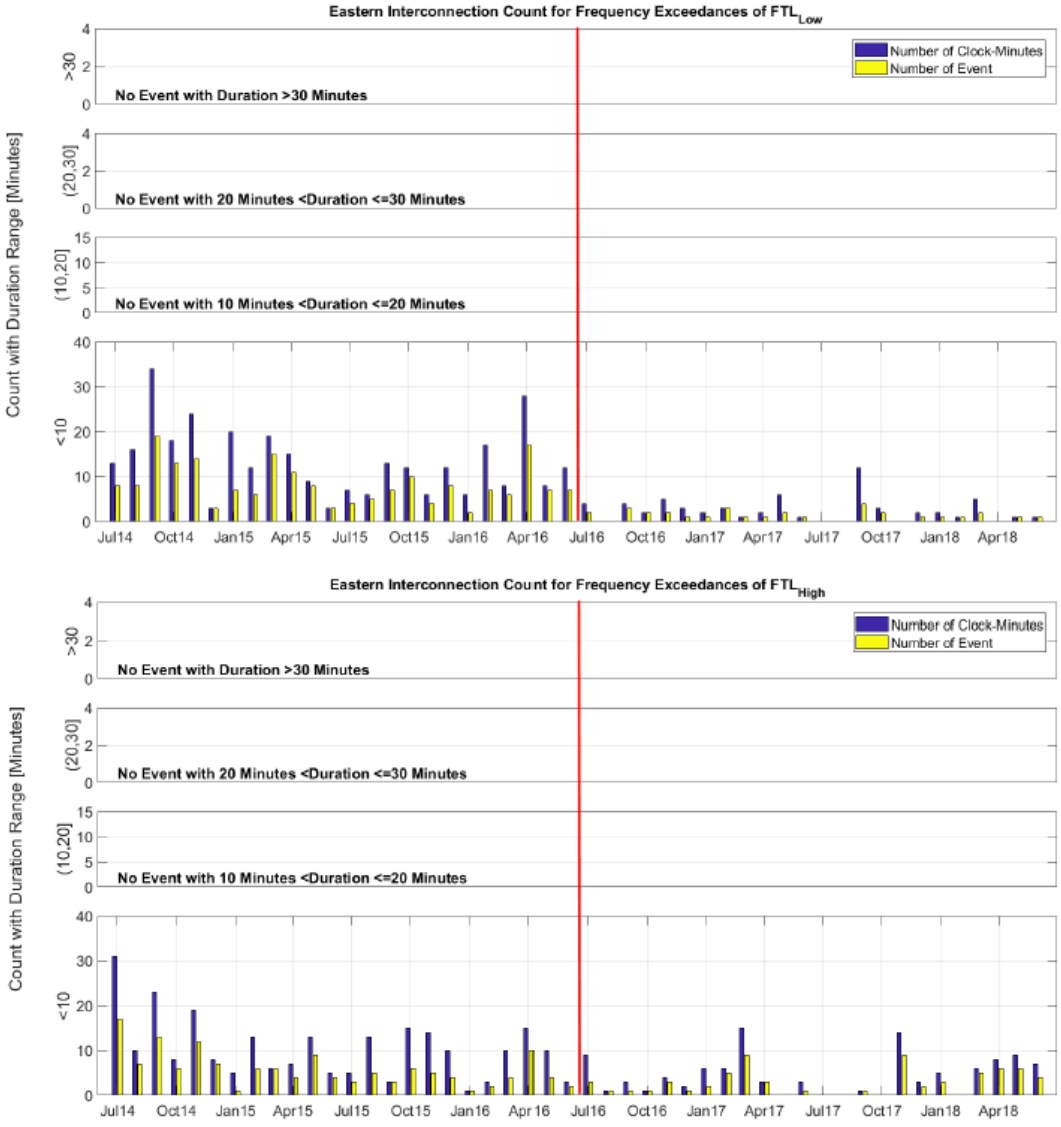


Figure 2.2: Eastern Interconnection FTL Exceedances

The Eastern Interconnection had no event with a duration greater than 10-minutes.

Table 2.2 shows the average change of monthly frequency exceedances of the FTL bands for both Eastern Interconnection and Western Interconnection before July 2016 and after the July 2016 implementation of reliability standard BAL-001-2.

Table 2.2: Monthly Changes in FTL Exceedances				
		Before July 2016	After July 2016	Difference
Eastern Interconnection				
FTL Band Range (mHz)		100 (59.95-60.05)	108 (59.946-60.054)	8
Average monthly number of clock-minutes	FTL_{Low}	13	3	-10
	FTL_{High}	10	4	-6
Average monthly number of events	FTL_{Low}	8	1	-7
	FTL_{High}	6	3	-3
Maximum event Duration (minutes)	FTL_{Low}	10	6	-4
	FTL_{High}	6	5	-1
Western Interconnection				
FTL Band Range (mHz)		136 (59.932-60.068)	136.8 (59.9316-60.0684)	0.8
Average monthly number of clock-minutes	FTL_{Low}	6	6	0
	FTL_{High}	3	4	1
Average monthly number of events	FTL_{Low}	3	2	-1
	FTL_{High}	1	1	0
Maximum event Duration (minutes)	FTL_{Low}	9	12	3
	FTL_{High}	9	12	3

The key findings for the Eastern and Western Interconnection include the following:

- For the Eastern Interconnection, beginning in July 2016, the number of clock-minutes and number of events with operation outside the FTL bounds decreased significantly.
- For the Western Interconnection, the monthly average number of exceedances showed no significant change for both FTL_{Low} and FTL_{High}.
- The maximum FTL exceedance event duration decreased for Eastern Interconnection.
- The maximum FTL exceedance event duration increased for Western Interconnection due to the aforementioned transmission events.

Conclusion: Analysis of the FTL exceedances and events in the Western and Eastern Interconnections over the two year period before and after implementation of BAAL found no evidence that would suggest that the implementation of BAAL resulted in an increase in FTL exceedances.

Chapter 3: Mitigation of SOL / IROLs

Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)

The purpose of the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)[10] is to mitigate flows on Qualified Paths to reliable levels during real-time operations. This is accomplished in two primary ways: the first is by the use of Qualified Controllable Device(s) that can change flow dynamics within the interconnection, and the second is by the use of curtailments.

The Commission approved regional Reliability Standard IRO-006-WECC-2[11] (Qualified Transfer Path Unscheduled Flow (USF) Relief) and the associated implementation plan (violation severity levels and violation risk factors by Letter Order[12]) on May 13, 2014. Reliability Standard IRO-006-WECC-2 standard became effective on July 1, 2014.

The following provides the process for the use of the WIUFMP and reflects modifications made in June 2013.

Transmission Operators of Qualified Paths may use the WIUFMP to reduce flows on Qualified Paths. The process has four steps:

Step 1: The Transmission Operator advises their RC of the situation and their intended actions.

Step 2: To the most practical possible extent, the Transmission Operator uses their own equipment to reduce unscheduled flows on the Qualified Path. PacifiCorp R.S. 439 Rev. 2b WECC Unscheduled Flow Mitigation Plan v. 3.1.0 Effective On: January 1, 2016, Page 4, "The Qualified Path Operator and their RC shall communicate periodically and as necessary regarding system status, Qualified Controllable Device positioning, the termination of, or taking additional steps in the WIUFMP based on current and anticipated system conditions."

Step 3: The Transmission Operator requests the coordinated operation of Qualified Controllable Devices to mitigate unscheduled flows on the Qualified Path. This request shall remain active for four (4) consecutive hours unless terminated or advanced to Step 4 by the Transmission Operator of the Qualified Path. To continue beyond the fourth consecutive hour, the Transmission Operator must re-issue the request before the completion of the third hour of the event or the event will automatically terminate at the completion of the fourth consecutive hour.

Step 4: The Transmission Operator requests curtailments in conjunction with the coordinated operation of Qualified Controllable Devices to mitigate unscheduled flows on the Qualified Path. Each hour is deemed to be a separate event for WIUFMP curtailment purposes. Therefore, Transmission Operators must re-issue a curtailment mitigation request for each hour that mitigation is desired.

[10] https://www.wecc.biz/Reliability/12c-FERC%20Accepted%20WIUFMP%202016%2003%2011.pdf
[11] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=IRO-006-WECC-2&Title=Qualified%20Transfer%20Path%20Unscheduled%20Flow%20(USF)%20Relief%20&Jurisdiction=United%20States
[12] https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Letter%20Order%20Approving%20IRO-WECC.pdf

Table 3.1 provides a list of the Qualified Paths under WIUFMP. **Table 3.2** and **Figure 3.1** show the number of unscheduled flow (USF) mitigation hours by path from 2014 through 2017. This historical data demonstrates that a downward trend of USF mitigation hours was seen during the last two years of the BAAL field trial and continued after the implementation of Reliability Standard BAL-001-2 in July 2016.

Table 3.1: List of Qualified Paths as of January 26, 2012

Path Code	Path Oper	Qualified Transfer Path	Qualifying Direction
66	**CISO**	**California–Oregon Intertie** Malin–Round Mt. 500-kV lines 1 and 2 Captain Jack–Olinda 500-kV line	**CCW** (North–South)
22	**APS**	**Four Corners–Central Arizona** Four Corners–Moenkopi 500-kV line Four Corners–Cholla 345-kV lines 1 and 2	**CW** (East–West)
23	**APS**	**Four Corners 345/500-kV Transformer** with Four Corners Unit 5 Out-of-Service OR at Greatly Reduced Output	**CW** (Low–High)
30	**WACM**	**TOT 1A Transmission Path** Hayden–Artesia 138-kV Meek–Rangely 138-kV Bears Ears–Bonanza 345-kV	**CW** (East–West)
31	**WACM**	**TOT 2A Transmission Path** Hesperus–Glade Tap 115-kV line Lost Canyon–Shiprock 230-kV line Waterflow–San Juan 345-kV line	**CW** (North–South)
36	**WACM**	**TOT 3 Transmission Path** Laramie River–Ault 345-kV line Laramie River–Story 345-kV line Archer–Ault 230-kV line Sidney–Spring Canyon 230-kV line Sidney–Sterling 115-kV line Cheyenne–Owl Creek 115-kV line Cheyenne–Ault 230-kV line	**CW** (North–South)

Table 3.2: WI Total USF Hours by Qualified Path

	Path 22	Path 23	Path 30	Path 31	Path 36	Path 66	Path 30/66	Path 31/30	Path 36/66	All
2014	0	0	301	82	324	1,491	11	2	53	2,264
2015	0	0	184	124	124	332	5	1	0	770
2016	19	0	211	118	313	548	25	13	80	1,327
2017	0	0	99	96	168	551	0	13	18	955

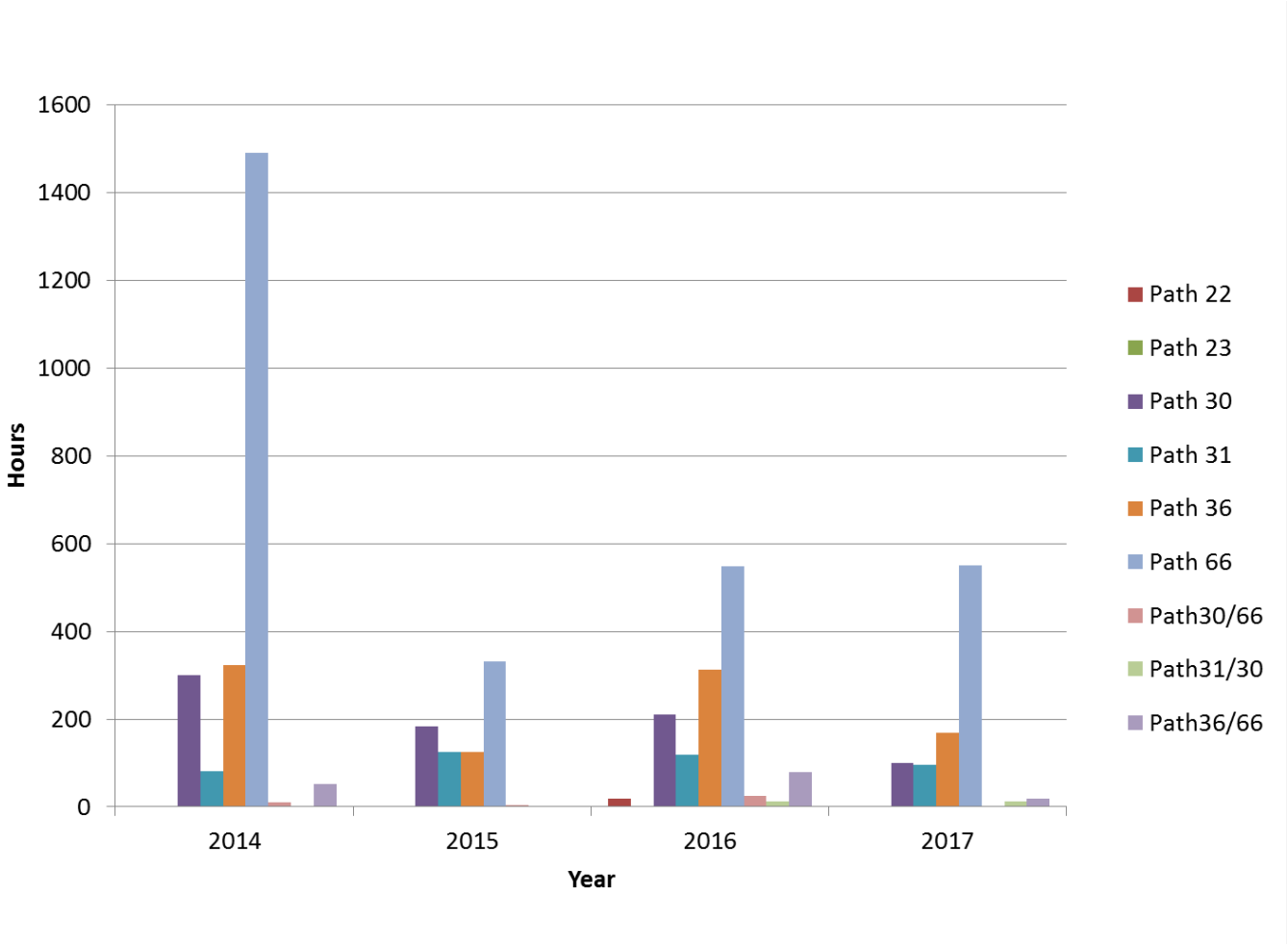


Figure 3.1: Total Yearly Qualified Path Hours

As reflected in **Table 3.2** and **Figure 3.1**, the USF mitigation hours for Path 66 were significantly higher in 2014 than 2015 through 2017. This was due to line deratings as a result of equipment maintenance that included a phase shifting transformer used for USF mitigation.

The BAAL field trial in the Western Interconnection began on March 1, 2010. SOL exceedances, USFs, and mitigation actions during the field trial were examined by WECC subcommittee and working group experts. Some of their findings are as follows:[13]

- SOL exceedances caused by unplanned derating of path SOL, redispatch of generation resources, or an increase in scheduled path use can be mitigated by re-dispatch of generation that reduced BA ACE.
- SOL exceedances caused by unscheduled flows on the path can be mitigated by the use of phase-shifting transformer tap position changes. There is evidence that phase-shifting transformer tap position changes reduce unscheduled flow.
- SOL exceedances caused by a combination of unscheduled flow and BA ACE contribution to unscheduled flow on the path can be mitigated by redispatch of generation resources with the RC requesting a BA to reduce its ACE to less than its L10 and reducing its scheduled path use.

[13] https://www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

The hours of coordinated operations of the phase shifters increased during the BAAL field trial period; however, due to changing seasonal patterns, a changing resource mix, unusual operating conditions, and other events, it is not possible to conclusively associate the increased hours of phase shifter operations with BAAL operation. Based on the Western Interconnection field trial, there were transmission constraints and many other attributing factors to the monitoring criteria; however, there was no conclusive evidence that these transmission constraints and USF were a direct result of BAAL.

Eastern Interconnection Transmission Loading Relief (TLR)

The NERC TLR Procedure is an Eastern Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. A TLR log contains the details of TLR incidents reported by Reliability Coordinators who are required to complete the logs whenever they invoke TLR Level 2 or above.

NERC Reliability Standard IRO-006-5 – Reliability Coordination – Transmission Loading Relief[14] and IRO-006-EAST-1 Transmission Loading Relief Procedure for the Eastern Interconnection[15] provide information regarding the use of TLRs. **Table 3.3** shows the TLR levels and corresponding Reliability Coordinator actions.[16]

Table 3.3: Transmission Loading Relief Levels

TLR Level	Reliability Coordinator Action	Comments
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations.	
2	**Hold** Transfers at present level to prevent SOL or IROL violations.	Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held. See Attachment 1 to IRO-006, Section 2.2.
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process. See Attachment 1 to IRO-006, Section 2.3 and Section 6.0.
3b	**Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.4 and Section 7.0.
4	**Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.	There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.5.

[14] https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf
[15] https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-1.pdf
[16] https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx

Table 3.3: Transmission Loading Relief Levels		
TLR Level	**Reliability Coordinator Action**	**Comments**
5a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point.	Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced ("pro rata") level. Pro forma tariff also requires curtailment/ REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.6, and Section 6.0.
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.7.
6	**Emergency Procedures**	Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Attachment 1 to IRO-006, Section 2.8.
0	**TLR Concluded**	**Restore** transactions. See Attachment 1 to IRO-006, Section 2.9.

Table 3.4 and **Figure 3.5** show the number by month and time range of the TLR issuances for the Eastern Interconnection for 2014 through 2017. This data shows a downward trend in TLR issuances. This TLR downward trend has been examined by many utility/subcommittee/working group industry experts including the Operating Reliability Subcommittee. Some of the contributing factors include:

- Operations Planning enhances seasonal coordinated operational studies.
- Coordinated RTO/ISO level congestion management processes (i.e. Locational Marginal Pricing, Market Flows Calculation, Security Constrained Unit Commitment and Security Constrained Economic Dispatch, etc.).
- The IDC/SDX Calculated Frequency and Real Time Data Exchange Operations Tool which runs every 5 minutes for real-time current hour calculations and every 15 minutes for next hour calculations.
- Data is exchanged every 5-15 minutes to IDC for TLR purposes.
- SOL/IROLs are mitigated via established local procedures.

Table 3.4: Eastern Interconnection Total TLRs													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2014	94	95	71	37	53	80	53	43	67	25	61	68	**747**
2015	79	85	37	41	31	48	45	27	17	46	17	23	**496**
2016	19	40	35	30	41	31	45	39	29	19	22	22	**372**
2017	12	14	42	18	23	25	6	7	18	36	18	24	**243**

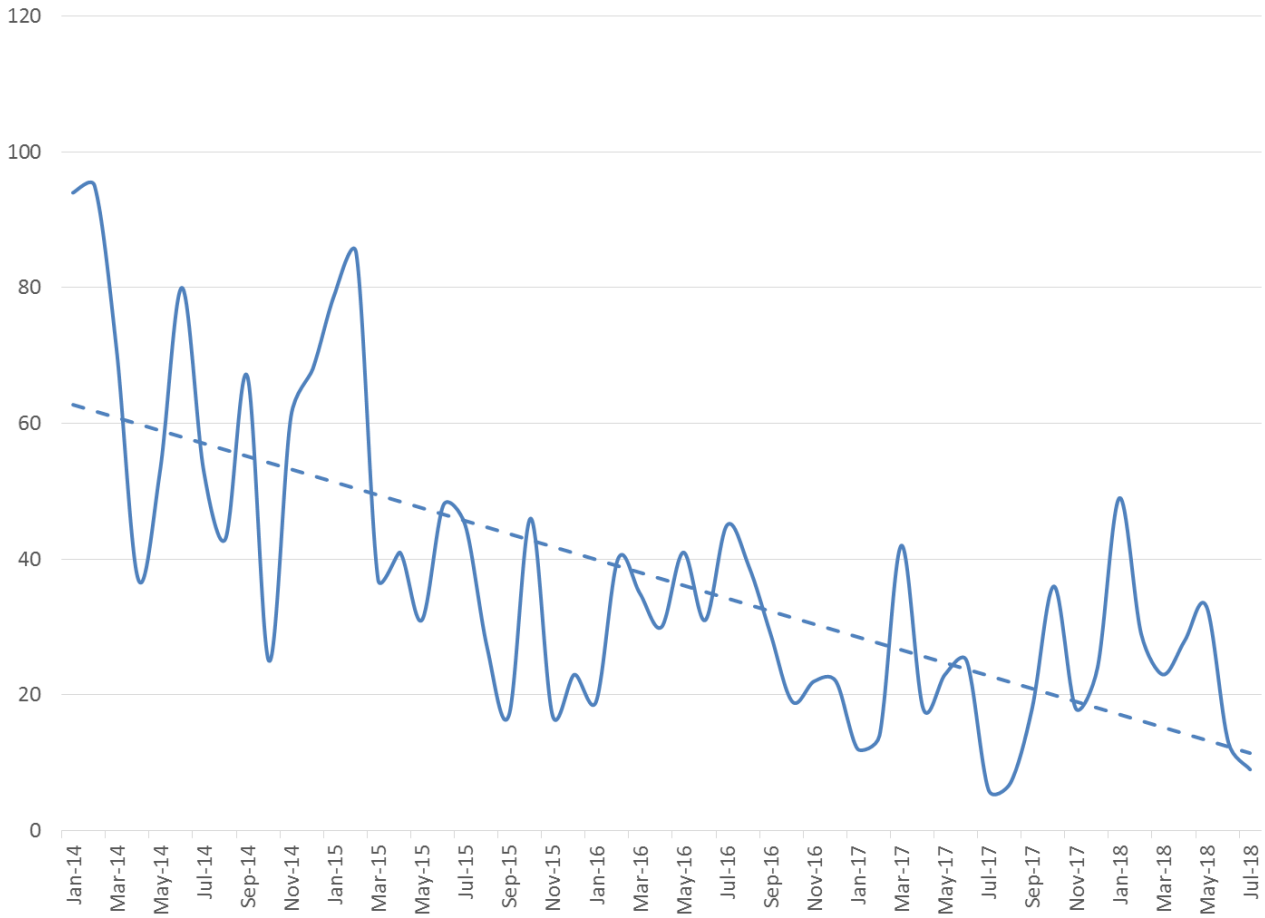


Figure 3.2: Eastern Interconnection Total Monthly TLRs

Historic TLR data from 2014 through the first two quarters of 2018 shows a downward trend in the issuance of TLR procedures and suggests that the replacement of CPS2 by BAAL caused no increase in the number or magnitude of transmission constraints due to unscheduled flow on the Eastern Interconnection.

Conclusion: Analysis of the USF mitigation hours in the Western Interconnection and TLR occurrences in the Eastern Interconnection over the period from 2014 through the first two quarters of 2018 found no evidence that would suggest that the implementation of BAAL resulted in an increase in either.

Chapter 4: Frequency Performance and Inadvertent Interchange

Frequency Performance

The foundation of the NERC Balancing Standards is the Control Performance Standard CPS1 found in Reliability Standard BAL-001-2. CPS1 is based on the variability of the one-minute averages of frequency deviation from schedule. Scheduled frequency is normally 60 Hz except during Time Error Corrections.

NERC posts the target frequency annual frequency variation in each Interconnection as "Epsilon 1." Epsilon 1 is the target root-mean-square (RMS) value of the one-minute averages of frequency deviation. CPS1 gives each Balancing Authority a portion of Interconnection performance based on its size through the BA Frequency Bias Setting (FBS) component of the calculation.

NERC and its Resources Subcommittee track the daily RMS1 values of frequency deviation as a fundamental indicator of Interconnection reliability over time. Frequency can become more variable or noisy for a wide spectrum of reliability issues, including congestion, multiple transmission line operations, generation losses, or general control issues. All of these problems cause more frequency variability.

Adverse frequency control impacts due to the implementation of BAAL, including increased movement of Inadvertent Interchange, would be reflected in an increase in RMS1.

The summary frequency performance data shown in **Table 4.1** and the graph shown in **Figure 4.1** demonstrate an improvement in the daily frequency performance in the Texas, Western, and Eastern Interconnections since the implementation of BAL-001-2 on July 1, 2016.

Table 4.1: Interconnection Frequency Performance Data

	Texas Target Ɛ1 = 0.0300 Hz		Western Target Ɛ1 = 0.0228 Hz		Eastern Target Ɛ1 = 0.0180 Hz	
	Median Daily RMS1	Mean Daily RMS1	Median Daily RMS1	Mean Daily RMS1	Median Daily RMS1	Mean Daily RMS1
2014 Q1–4	0.0180	0.0181	0.0175	0.0176	0.0145	0.0145
2015 Q1–4	0.0151	0.0151	0.0176	0.0177	0.0135	0.0134
2016 Q1–4	0.0145	0.0146	0.0177	0.0178	0.0142	0.0141
2017 Q1–4	0.0149	0.0150	0.0172	0.0172	0.0138	0.0138
2018 Q1-–	0.0144	0.0146	0.0163	0.0165	0.0139	0.0139

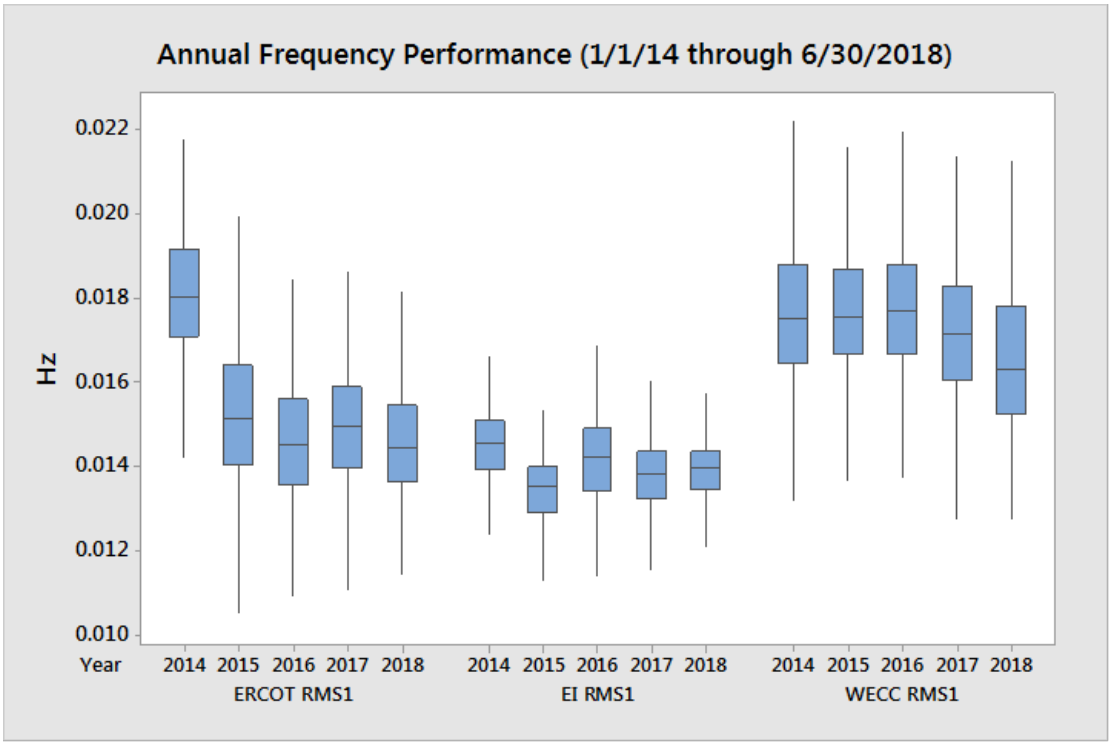


Figure 4.1: RMS1 Annual Frequency Performance

The Texas Interconnection had a reduction in median daily RMS1 each year from 2014 (0.0180 Hz) through the first two quarters of 2018 (0.0144 Hz) with the exception of 2017 (0.0149 Hz), which had a slight increase. The general reduction in RMS1 over the period also reflect the implementation of a regional frequency response standard, BAL-001-TRE-1, which went into effect in two phases beginning April 2015. BAL-001-TRE-1 was fully effective in October 2015 and required all generators to have a working governor and tightened deadband settings.

The Western Interconnection had slight increases in median daily RMS1 from 2014 (0.0175 Hz) through 2016 (0.0177 Hz) followed by significant decreases in 2017 (0.0172 Hz) and the first two quarters of 2018 (0.0163 Hz). The mean daily RMS1 also decreased from 2016 (0.0172 Hz) through the first two quarters of 2018 (0.0165 Hz).

The Eastern Interconnection median daily RMS1 varied slightly within a range of 0.6 mHz each year from 2014 through the first two quarters of 2018. While the median daily RMS1 was slightly higher in the first two quarters of 2018 (0.0139 Hz) as compared to 2017 and 2016 (0.0138 and 0.0142 Hz, respectively), there was a noticeable reduction in variability as shown in the box and whisker plots in **Figure 4.1**.

Both the Western and Eastern Interconnections had slight increases in the median and mean daily RMS1 in 2016. In addition to the implementation of Reliability Standard BAL-001-2 and BAAL in July 2016, the minimum bias settings for both Interconnections were also reduced in April 2016 in accordance with Reliability Standard BAL-003-1.1. This change resulted in a temporary increase in frequency variability for both Interconnections in April 2016, which would be reflected in the 2016 RMS1 performance shown in **Table 4.1** and **Figure 4.1**.

Conclusion: Analysis of the frequency data for the Texas, Western, and Eastern Interconnections over the period from 2014 through the first two quarters of 2018 found no evidence that would suggest that the implementation of BAAL resulted in a decrease in frequency performance.

Inadvertent Interchange

Inadvertent interchange is the difference between a BA's net actual Interchange and net scheduled interchange. BAs calculate and record hourly inadvertent interchange, which includes all ac and dc tie lines that connect to its adjacent BAs in the same Interconnection and interchange served by jointly owned generators for on-peak and off-peak periods. All BAs reconcile their monthly inadvertent interchange with adjacent BAs using agreed-to accounting data with like MWh values and opposite signs. The sign (+ or -) indicates the direction of the monthly net inadvertent interchange flows. The monthly inadvertent interchange for each BA is recorded in the NERC Inadvertent Interchange Reporting Tool.

A BA's on-peak and off-peak monthly inadvertent interchange is added to the accumulated balances from the previous month. It is the responsibility of each BA to minimize accumulated inadvertent interchange balances. When a BA's accumulated inadvertent balances exceed a predetermined threshold, depending on Interconnection, the BA should start a form of inadvertent payback method that includes a target of driving their balance down towards zero in accordance with the North American Energy Standards Board requirements. Additional information can be found in the Reliability Guideline Inadvertent Interchange, which was approved by the NERC Operating Committee.[17]

The NERC Inadvertent Interchange Working Group monitors the monthly and accumulated inadvertent interchange for each BA to identify trends at the BA and Interconnection levels. **Table 4.2** shows quarterly aggregated inadvertent interchange data for the BAs in the Eastern and Western Interconnections. Adjacent BAs reconcile their monthly inadvertent interchange with like values but opposite signs. The data shown in **Table 4.2** is the sum of the absolute values of accumulated inadvertent for all BAs in the given Interconnection.

Table 4.2: Quarterly Inadvertent Interchange Accumulations

	Jun 16	Nov 16	Feb 17	May 17	Aug 17	Nov 17	Feb 18	Apr 18
Eastern Interconnection								
Ave Absolute On Peak Inadvertent	37,606	31,152	29,347	25,710	19,836	16,606	14,135	11,349
Median Absolute On Peak Inadvertent	1475	545	648	1262	953	693	784	703
Ave Absolute Off Peak Inadvertent	16,075	15,331	16,783	13,565	9,363	6,005	4,474	3,107
Median Absolute Off Peak Inadvertent	1,684	487	573	1,080	1,078	1,264	787	717
Western Interconnection								
Ave Absolute On Peak Inadvertent	649	1,031	851	1,337	1,277	1,603	1,596	1,536
Median Absolute On Peak Inadvertent	156	316	163	414	247	532	411	520
Ave Absolute Off Peak Inadvertent	869	1041	459	908	819	560	417	526
Median Absolute Off Peak Inadvertent	173	380	137	404	274	171	114	178

Conclusion: If BAAL operation was resulting in increased inadvertent interchange, it would be evident in the quarterly on-peak and off-peak accumulations shown in Table 4.2. The Eastern Interconnection shows a declining trend in accumulated inadvertent interchange due at least in part to the efforts of the Inadvertent Interchange Working Group to monitor and assist BAs in reducing their accumulations. The Western Interconnection uses automated time error correction and manages inadvertent interchange balances in accordance with Regional standard BAL-004-WECC-2. As with the Eastern Interconnection, the aggregated data for the Western Interconnection does not show evidence of an increasing inadvertent trend that could be due to BAAL operation.

[17] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_Inadvertent_Interchange_v1.1_20171213.pdf

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	**Docket No. RR10-1-___**
RELIABILITY CORPORATION	**)**	**Docket No. RR13-3-___**

ANNUAL REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON WIDE-AREA ANALYSIS OF TECHNICAL FEASIBILITY EXCEPTIONS

The North American Electric Reliability Corporation ("NERC") hereby provides the 2018 Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (the "2018 Annual Report") in compliance with Paragraphs 220 and 221 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 706[1] and Appendix 4D of the NERC Rules of Procedure ("ROP"). The 2018 Annual Report covers the period from July 1, 2017 through June 30, 2018.

I. BACKGROUND

In Order No. 706, FERC approved eight Critical Infrastructure Protection ("CIP") Reliability Standards and, among other things, directed NERC to develop a set of conditions or criteria that a registered entity must follow to obtain a Technical Feasibility Exception ("TFE") from specific requirements in the CIP Reliability Standards.[2] The Commission stated that the TFE process must include: mitigation steps, a remediation plan, a timeline for eliminating the use of the TFE unless appropriate justification is provided, regular review of the continued need for the

[1] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").

[2] *Id.* at P 178.

TFE, internal approval by senior managers, and regional approval through the Electric Reliability Organization ("ERO").[3]

Order No. 706 also required that NERC submit an annual report to the Commission that provides a wide-area analysis of the use of TFEs and their effect on Bulk-Power System reliability. The Commission stated:

> The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception . . . [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region . . . .[4]

In October 2009, NERC filed amendments to its ROP to implement the Commission's directive in Order No. 706, proposing Section 412 (Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards) and Appendix 4D (Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards). On January 21, 2010, the Commission approved NERC's amended ROP.[5]

On April 8, 2013, NERC filed revisions to Appendix 4D of the ROP to streamline the TFE approval process, reflecting NERC, Regional Entity and industry experience processing TFE

3 *Id*. at P 222.

4 *Id*. at PP 220 - 21.

5 *North American Electric Reliability Corp*., 130 FERC ¶ 61,050 (2010), *order on compliance*, 133 FERC ¶ 61,008 (2010) ("October 1 Order"), *order on reh'g*, 133 FERC ¶ 61,209 (2010), *order on compliance*, 135 FERC ¶ 61,026 (2011) ("April 12 Order"). The Commission requested further information and clarification regarding certain aspects of the TFE process. On April 21, 2010, NERC submitted its compliance filing in response to the January 21 Order. On October 1, 2010, the Commission issued an order accepting NERC's April 2010 filing as partially compliant and directing further changes to the TFE Procedure. *See* October 1 Order. On December 23, 2010, NERC submitted a compliance filing in response to the Commission's October 1 Order, which the Commission subsequently accepted. *See* April 12 Order.

requests since the inception of the program. On September 3, 2013, FERC approved the proposed revisions and directed limited revisions to Appendix 4D, including modifications to: (1) specify a time frame for reporting Material Changes to TFEs upon identification and discovery; and (2) require the annual TFE report to include information on Material Change Reports and TFE expiration dates.[6] NERC submitted a compliance filing consistent with the directives from the September 2013 Order, which the Commission approved on January 30, 2014.[7] Sections 11.2.4 and 13 of Appendix 4D set forth the requirements for the annual TFE report, as modified in accordance with the September 2013 Order.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. 2018 ANNUAL REPORT

This section provides the TFE information required by Appendix 4D of the ROP. In accordance with Appendix 4D, NERC prepared the 2018 Annual Report in consultation with the Regional Entities. The Regional Entities provided regular reports to NERC regarding the types of Covered Assets for which the Regional Entities have approved TFEs.[8] In addition, each Regional

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6 *North American Electric Reliability Corp.*, 144 FERC ¶ 61,180 (2013) ("September 2013 Order").

7 *North American Electric Reliability Corp.*, Docket No. RR13-3-001 (Jan. 30, 2014) (unpublished delegated letter order).

8 Appendix 2 of the ROP defines the term "Covered Asset" as "any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to" a TFE.

Entity provided information on the elements identified in Section 13 of Appendix 4D to be included in the 2018 Annual Report. NERC compiled and analyzed the TFE data provided by the Regional Entities in preparation for the 2018 Annual Report.

The 2018 Annual Report is the last annual report that will depict TFE data for Southwest Power Pool - Regional Entity ("SPP-RE"). The dissolution of SPP-RE resulted in the transition of 122 registered entities to Midwest Reliability Organization ("MRO") and SERC Reliability Corporation ("SERC"). Those Regional Entities are responsible for maintaining TFE information for the registered entities that have been assigned to those regions. Both Regional Entities' annual reports incorporated the TFE information that SPP-RE had also reported, providing assurance that TFE information is complete and accurate.

The transition to the CIP cybersecurity Reliability Standards approved in Order No. 791,[9] which are commonly referred to as the CIP version 5 standards, resulted in a significant decrease to the number of TFEs. As a result, the Regional Entities have been able to better evaluate the risk and impact of TFEs, and gain a better understanding of the value of the TFE process compared to the administrative burden it places on registered entities and Regional Entities. As discussed below, NERC is considering alternatives to the current TFE process to reduce the burden.

The following is the summary of the TFE data reported by each Regional Entity for the elements identified in Section 12.1 of Appendix 4D:[10]

1. Frequency of use of the TFE Request process

The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests

[9] *Version 5 Critical Infrastructure Protection Reliability Standards*, 145 FERC ¶ 61,160 (2013) ("Order No. 791"), *order on clarification and reh'g*, 146 FERC ¶ 61,188 (2014).

[10] Unless stated otherwise, a table or reference to "2018" refers to the reporting period for this report: July 1, 2017 – June 30, 2018.

> *that have been submitted and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their TFE Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their TFE Expiration Dates during the ensuing year.*

The data from this reporting period indicates that the number of registered entities that are engaging in the TFE program continues to decline as does the number of total TFEs. Figure 1 provides data on the use of the TFE program. The first column of Figure 1 shows the number of registered entities subject to the CIP Reliability Standards. The CIP Reliability Standards apply to the registered entities designated in Applicability Section 4.1 of CIP-002-5 through CIP-011-2 (e.g., Balancing Authority, certain Distribution Providers, etc.). From an industry-wide perspective, the number of "CIP applicable" entities in the U.S. (i.e., with registrations to which the CIP Reliability Standards apply) has increased by less than three percent since last year's report, from 1400 to 1442, as depicted in the first column of Figure 1.

The second column of Figure 1 depicts the number of CIP applicable registered entities (i.e., those listed in the first column) that report having high or medium impact BES Cyber Systems ("BCS").[11] In 2017, 594 registered entities claimed to have systems that meet that criteria; in 2018, that number decreased nearly 40% to 365. Much of this decrease can be attributed to consolidation of entity registration and Multi-Regional Registered Entities.

The third column of Figure 1 shows the number of registered entities with high or medium impact BCS (i.e., those listed in the second column) that have active TFEs. Overall, that percentage decreased by nearly 50% in 2018. While the number of registered entities in column 2 of Figure 1 was significantly lower, the results show that in general, a registered entity with BCS has an

[11] During the reporting period, only requirements applicable to high and medium impact BCS were subject to TFEs.

approximately 20-25% likelihood of having a TFE. Prior to implementation of the CIP version 5 standards, 100% of registered entities with Critical Cyber Assets had TFEs.

Figure 1 – Frequency of Use (7/1/2017 to 6/30/2018)

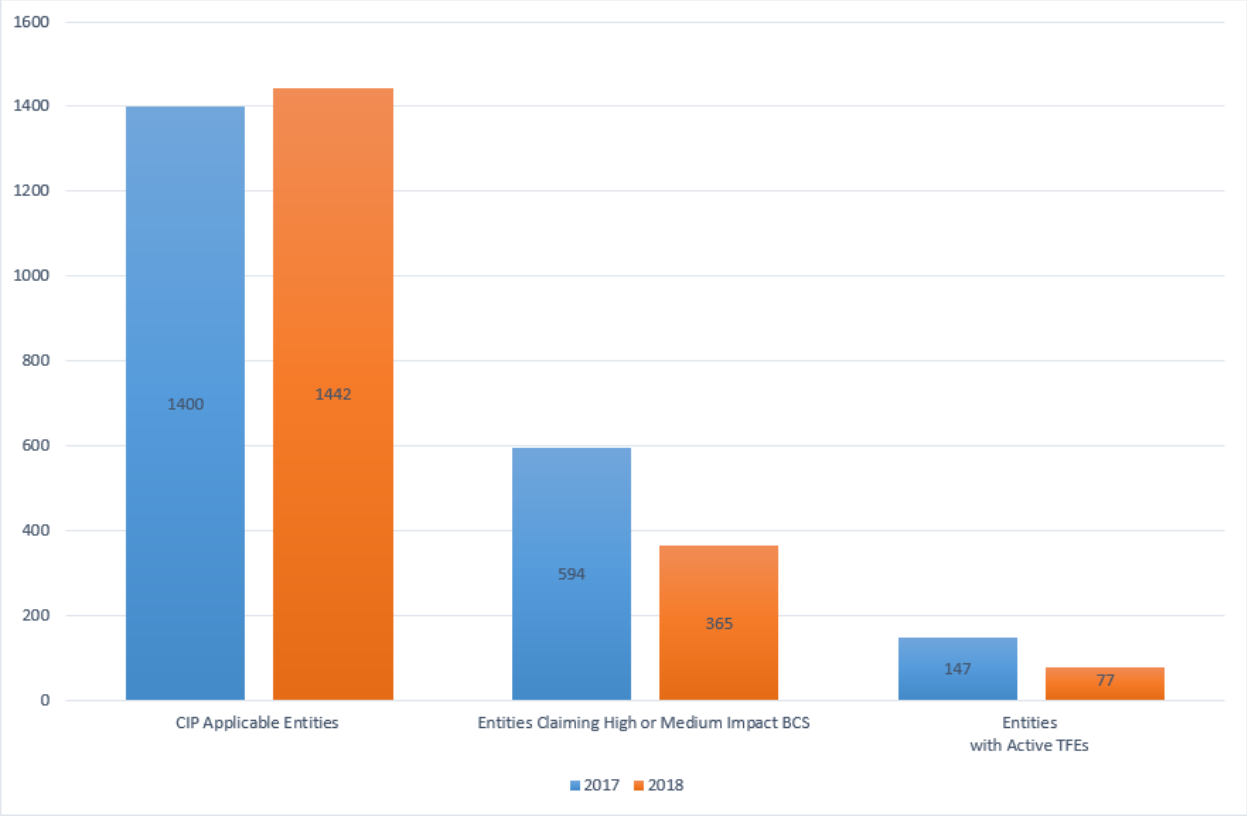


Figure 2 depicts the number of registered entities, by Regional Entity, with TFEs from 2016 through 2018. Each Regional Entity shows a significant reduction in the number of registered entities with TFEs from 2016 to 2017 (i.e., as the CIP version 5 standards were implemented). This trend moderated in 2018 in most regions, although the Western Electricity Coordinating Council ("WECC") saw a slight increase in the number of registered entities with TFEs in 2017 followed by a drastic decline in 2018. WECC is currently examining the reasons for the sharp decline.

As noted, because SPP-RE's compliance responsibilities ended on July 1, 2018, the TFE data for its transitioning registered entities was included in the 2018 annual report data submittals

from MRO and SERC. A total of 122 registered entities transitioned to MRO or SERC from SPP-RE. NERC estimated the number of these registered entities with TFEs. The transition did not impact data pertinent to other TFE activity addressed in this report.

Figure 2 – Number of Registered Entities with TFEs

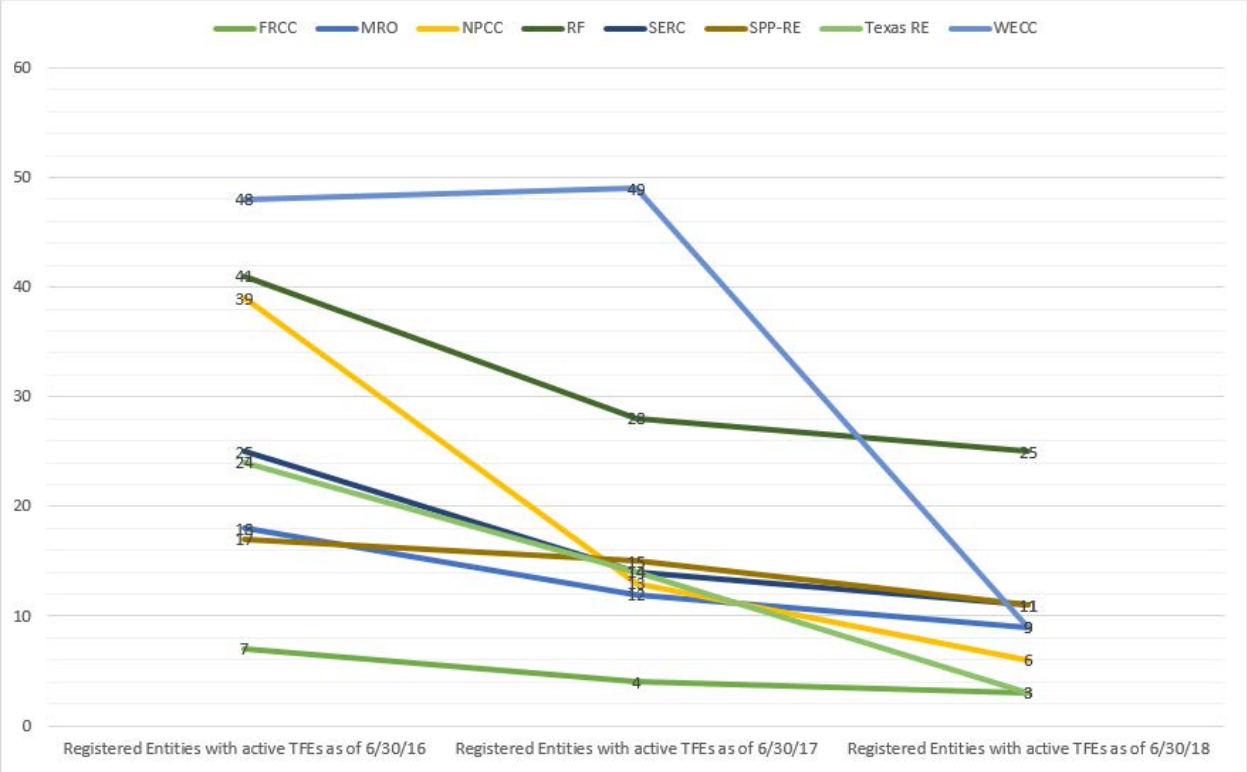


Figure 3 depicts the percentage of registered entities with TFE activity (e.g., submissions of new requests or amendments, terminations, etc.) in 2018 as compared to 2017. This percentage has been fairly consistent since July 1, 2016. Last year the average across the ERO Enterprise was 7.36% whereas this year's average is 7.49%.

Figure 3 – TFE Activities, per Number of Applicable Registered Entities

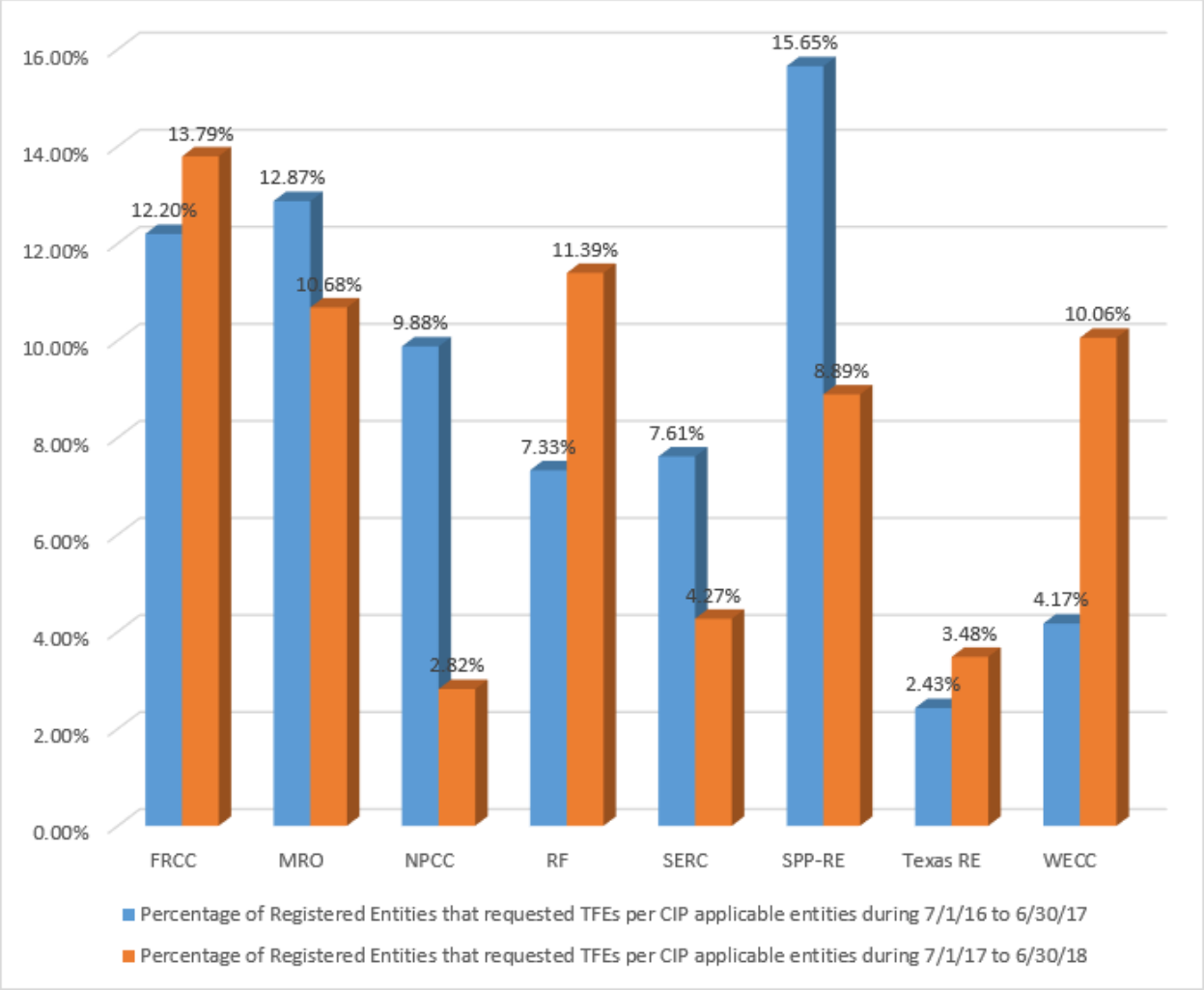


Figure 4 depicts TFE activity by comparing the number of TFE "transactions" (submittals, modifications, terminations, etc.) to the number of active TFEs from registered entities with high or medium impact BES Cyber Systems. The 2017 TFE report showed that, overall, there were 17.5% more TFE transactions than active TFEs during the period. That number, however, is the average across the ERO Enterprise. Three Regional Entities had disproportionate levels of TFE activity: The Florida Reliability Coordinating Council ("FRCC") reported TFE activity that

exceeded 80% of the active TFEs in 2017, while MRO and SPP-RE both reported more transactions than the total number of active TFEs.

In 2018, the overall average jumped to nearly 30%. The differences between the Regional Entities are less pronounced in 2018. The flattening of the differences between the Regional Entities is due, in part, to the significant decrease in the number of registered entities to which the CIP Reliability Standards apply, as discussed above. Figure 4 illustrates that despite the decrease in the number of active TFEs and the apparent leveling of TFE activity among Regional Entities, the level of effort needed to maintain a TFE continues to increase. TFE record-keeping, as currently required in Appendix 4D of the NERC ROP, is burdensome for the Regional Entities and registered entities alike, creating work efforts that may outweigh any perceived benefit to reliability.

Figure 4 – TFE Activity Compared to the Number of Active TFEs

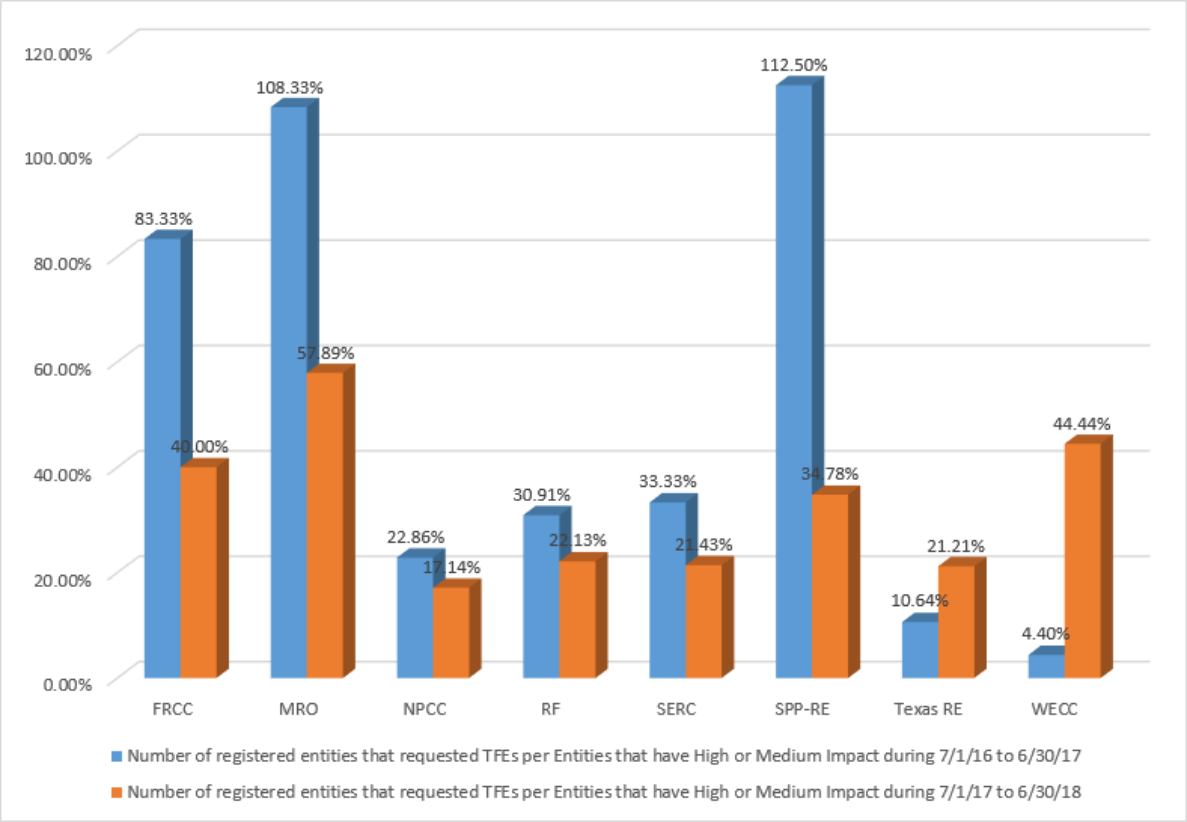


Figure 5 depicts the percentage of registered entities with TFE program activity, compared to the number of registered entities with active TFEs. This statistic stayed roughly the same between the 2017 and 2018 reporting periods. In 2017 and 2018, over 140% of registered entities with active TFEs had to take administrative action during the reporting period, which indicates that the administrative burden for maintenance of TFEs, to both registered entities and Regional Entities, has continued at very high levels.

Figure 5 – Percentage of TFE Interaction per Active TFEs

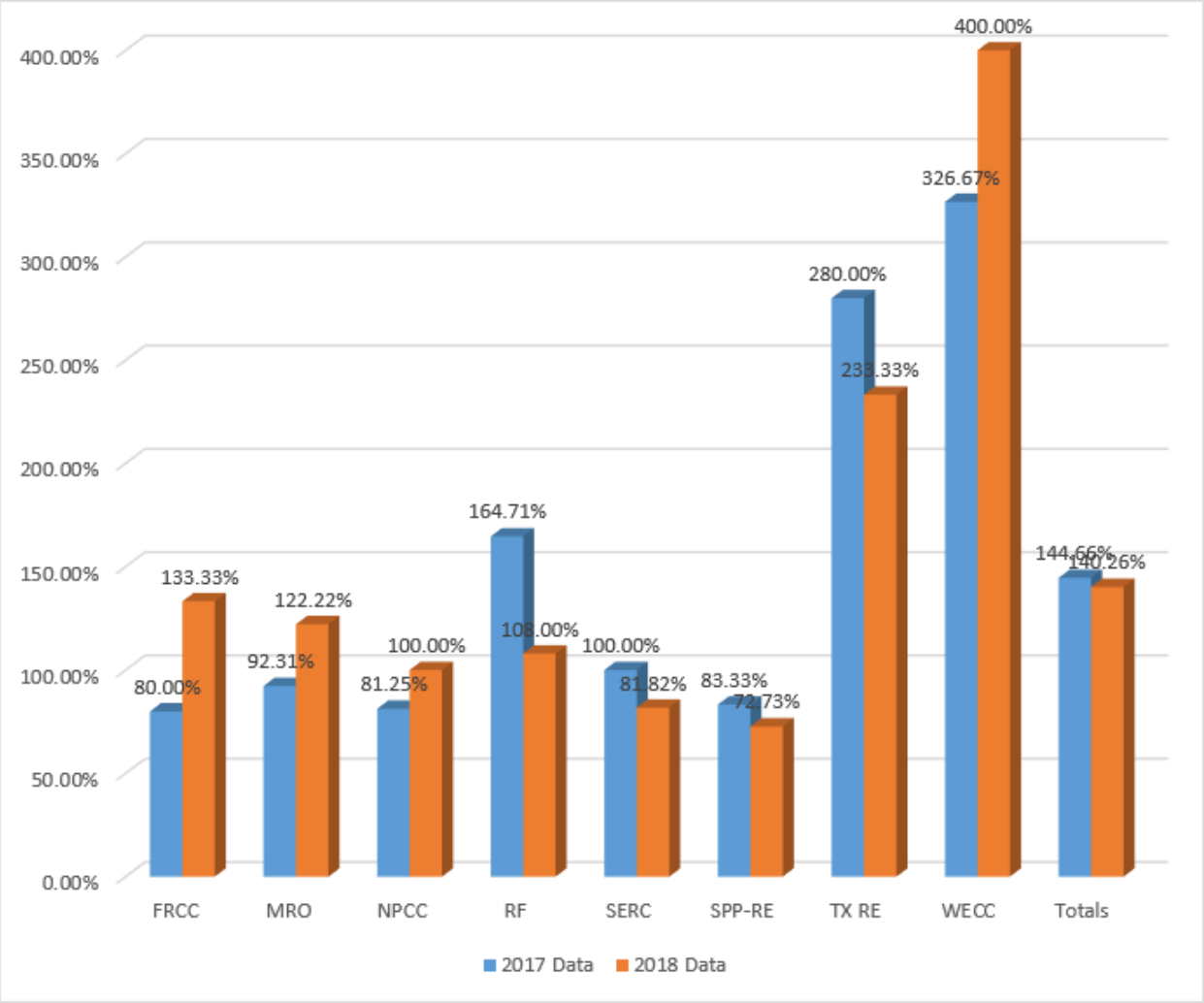


Figure 6 depicts the percentage of registered entities with TFE program activity, compared to the number of total active TFEs. This percentage shows that the number of administrative

actions needed to maintain the program exceeded the number of active TFEs. For 2018, this percentage decreased significantly from 2017 levels, although the percentages in 2017 were unusually high as the CIP version 5 standards went into effect during that reporting period causing registered entities to submit an amendment to either terminate the TFE or to update the TFE for material changes.

Figure 6 – Percentage of TFE Program Activity Correlated with Total Active TFEs

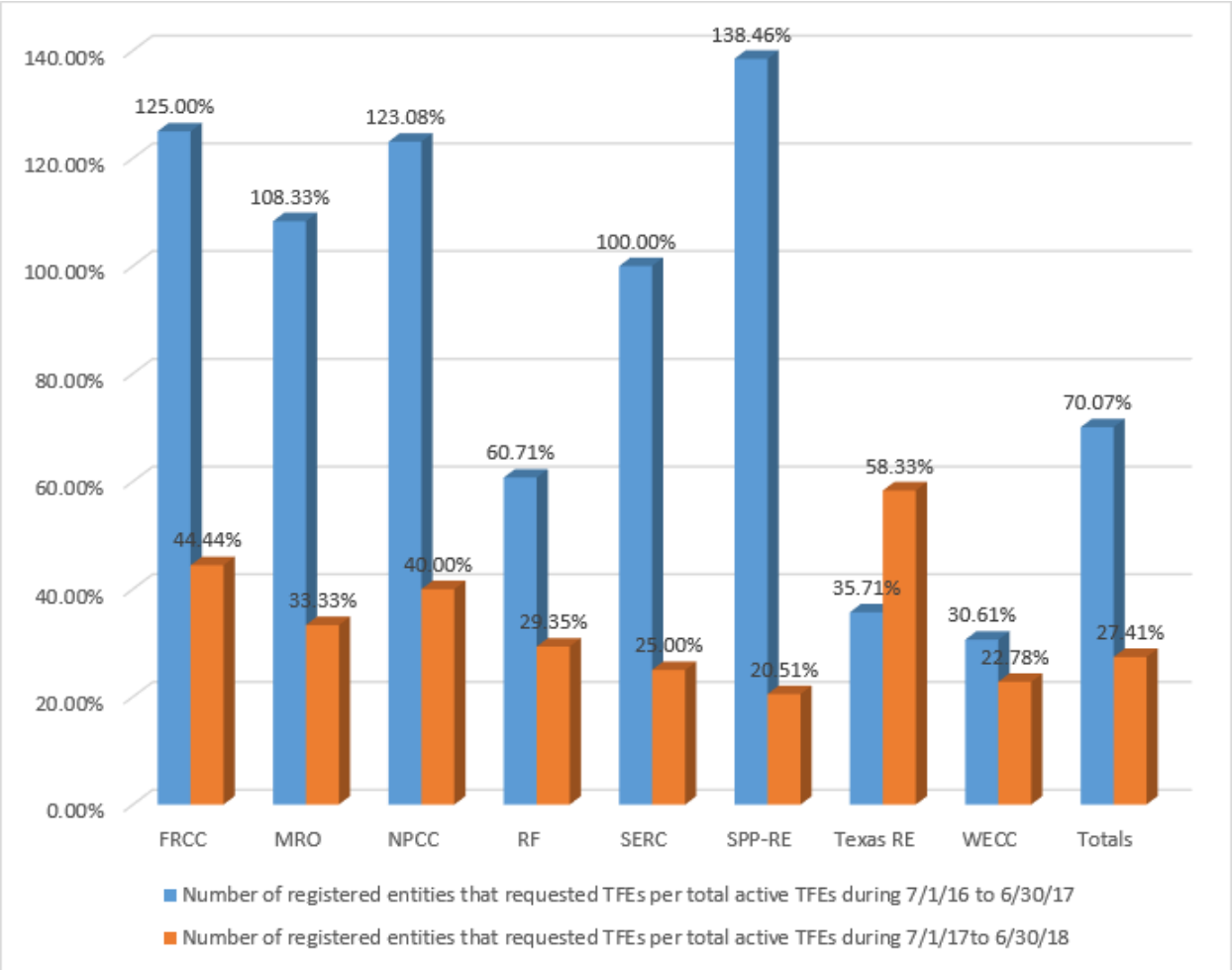
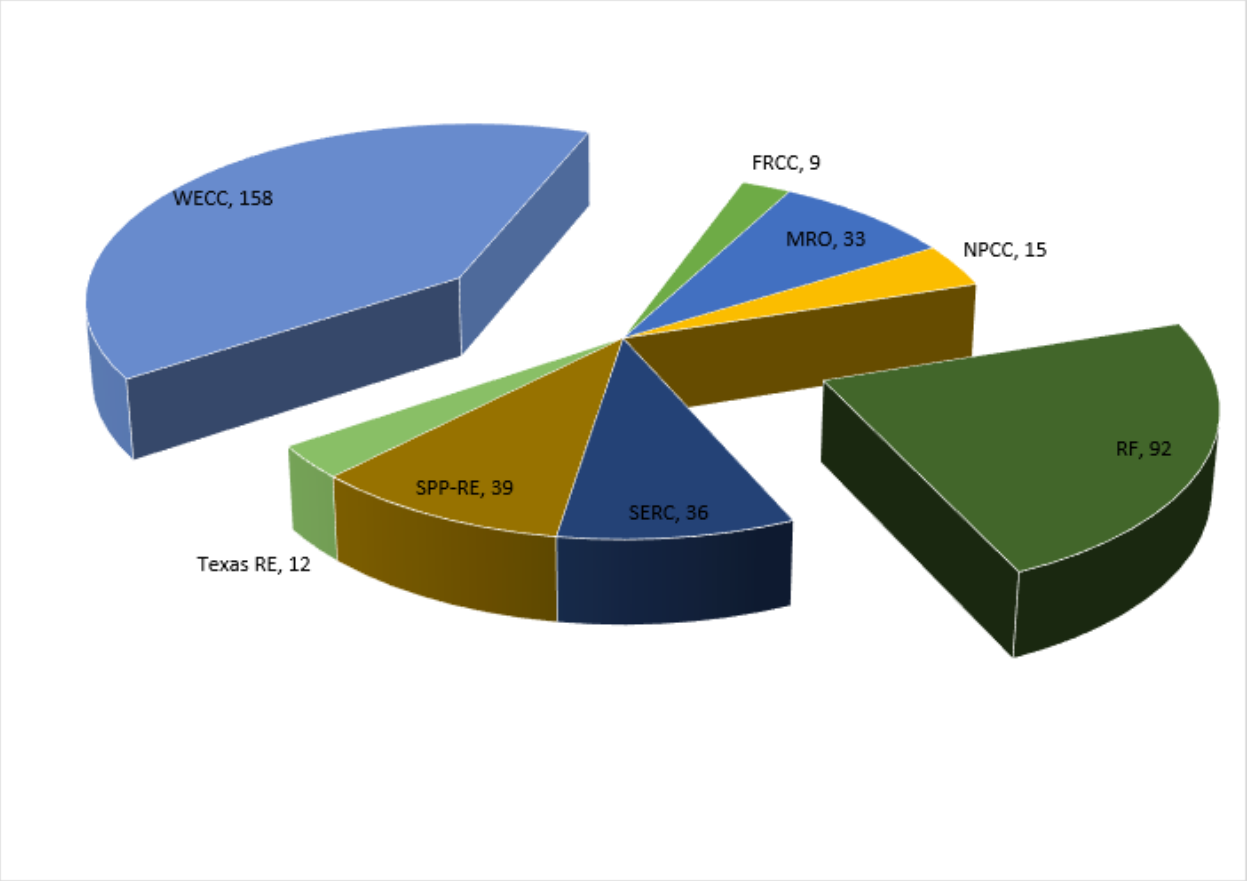


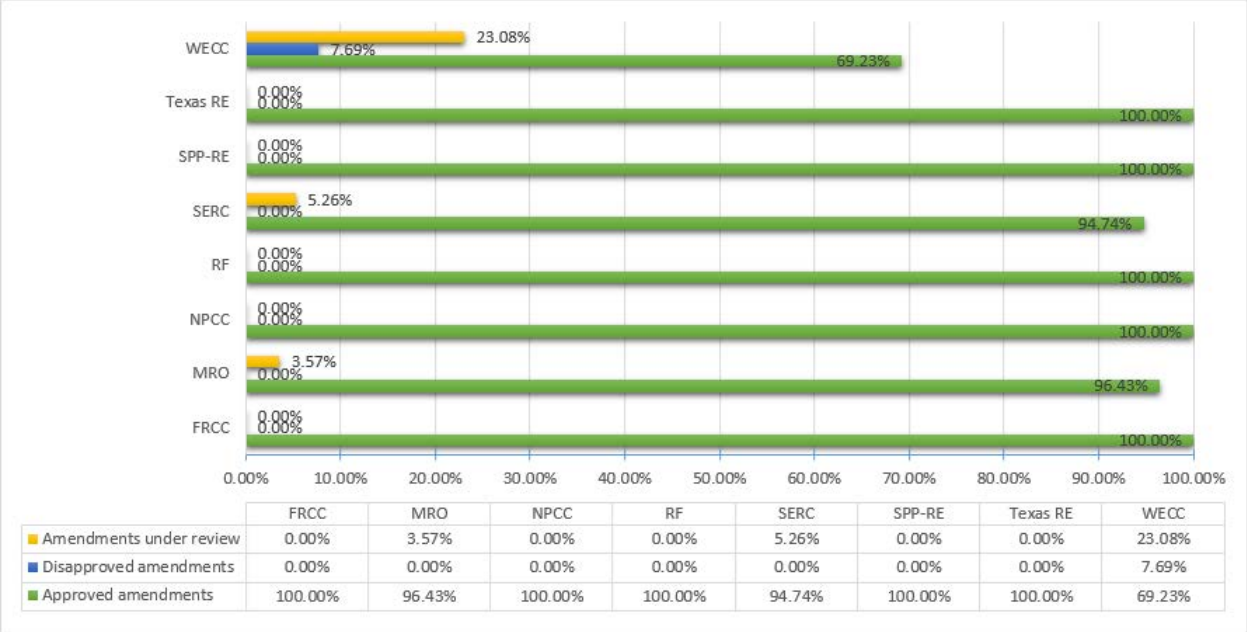
Figure 7 depicts the breakout, per Regional Entity, of the 394 active TFEs. Registered entities in WECC and the ReliabilityFirst ("RF") continue to maintain the majority of the active TFEs, while FRCC processes the least.

Figure 7 – Total number of Active TFEs



A total of 63 TFE amendments were submitted during the reporting period. Figure 8 provides a breakdown of that activity by Regional Entity. As shown below, the majority of the amendments submitted were approved. Of the 63 amendments that were submitted, four (or 6.35%) were not approved. This equates to a 0.006% amendment disapproval percentage across the ERO Enterprise. WECC is the only region that rejected amendments. As of June 30, 2018, WECC, SERC, and MRO had a number of amendments still under review.

Figure 8 – Submitted TFE Amendment Activity



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	Texas RE	WECC
Amendments under review	0.00%	3.57%	0.00%	0.00%	5.26%	0.00%	0.00%	23.08%
Disapproved amendments	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.69%
Approved amendments	100.00%	96.43%	100.00%	100.00%	94.74%	100.00%	100.00%	69.23%

Figure 9 depicts the average quantity of TFEs for each registered entity. As shown below, the ERO Enterprise average is five TFEs per registered entity. This ERO-wide number is skewed by WECC's average of 17.56, which is higher due to a single registered entity with 32 active TFEs. In addition, two other registered entities in WECC's footprint have more than 12 TFEs each. NERC is collaborating with WECC to determine if each of these TFEs are needed or could be consolidated.

Figure 9 – Average TFE Quantity per Registered Entity

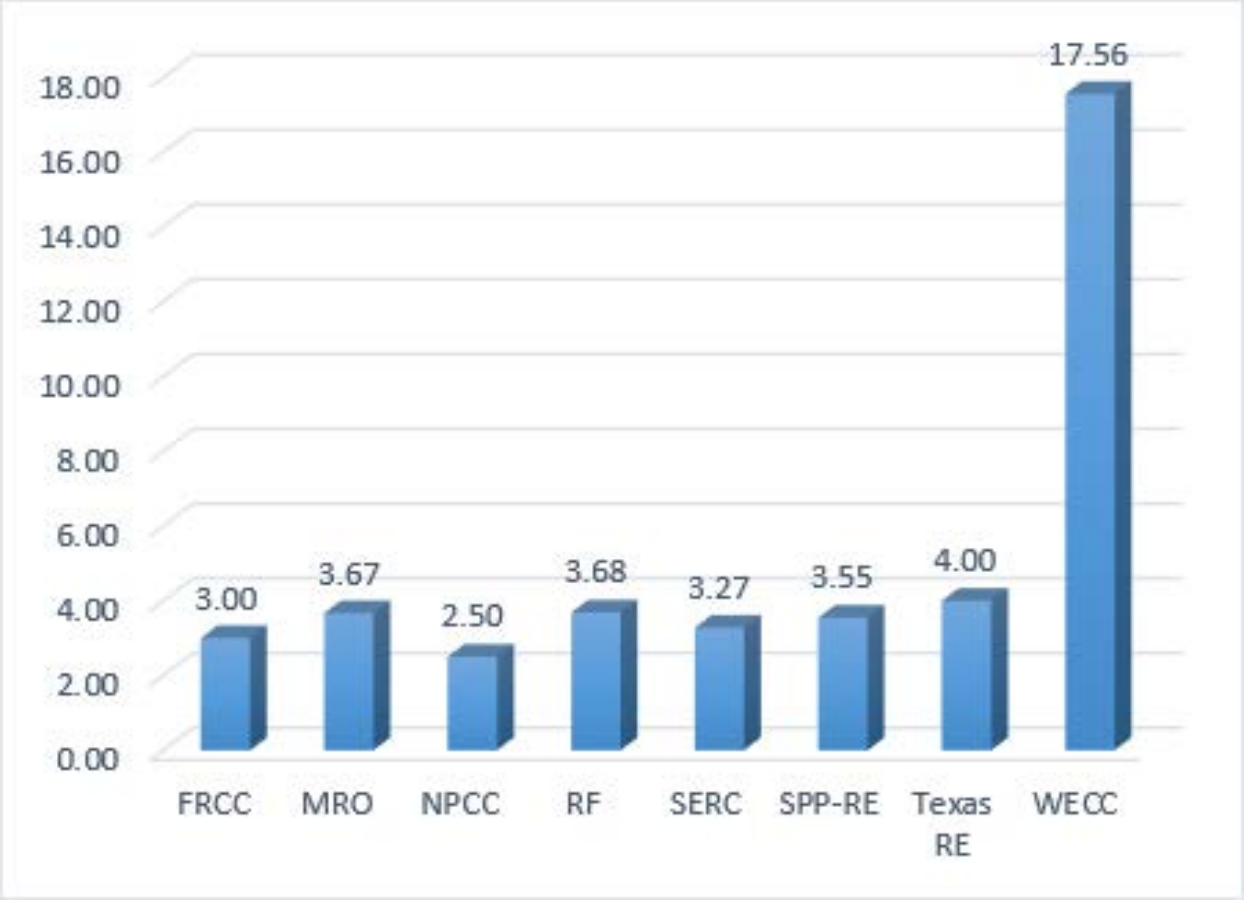
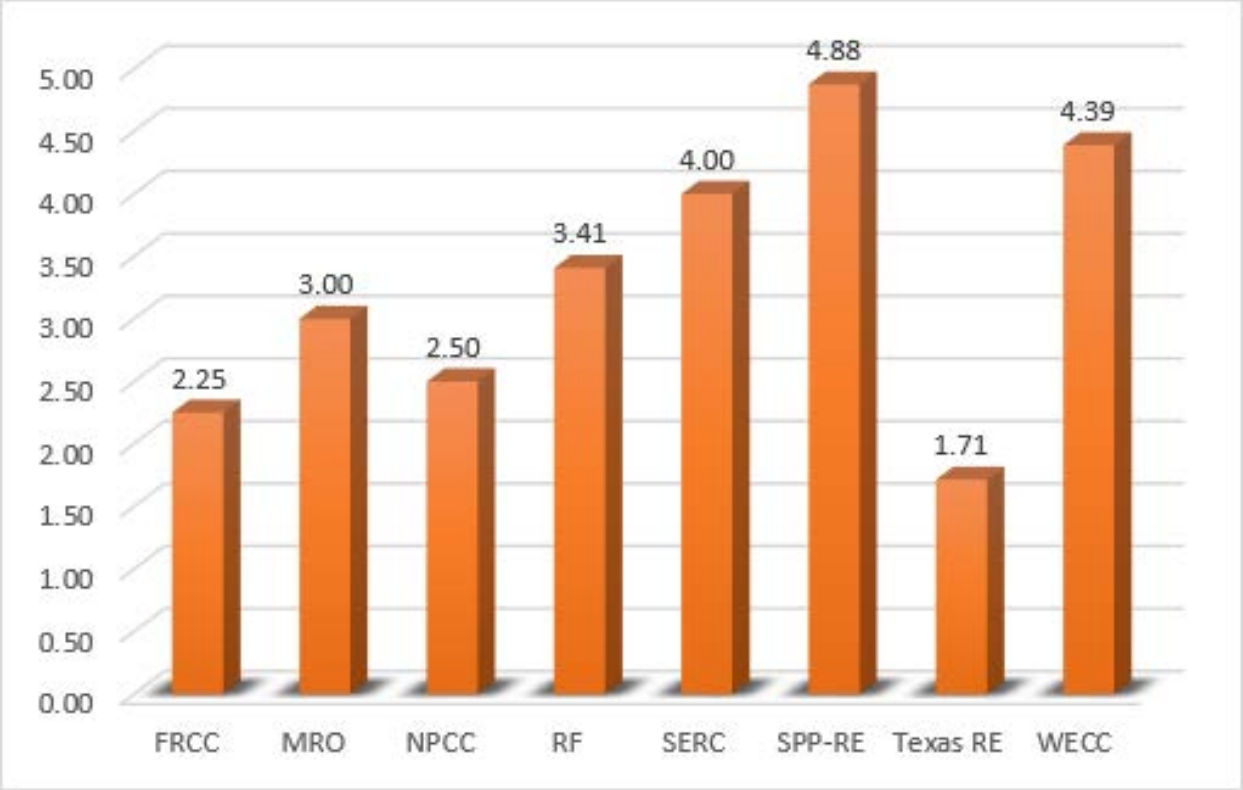


Figure 10 depicts the average percentage of transactions per TFE during the report period. The overall average for the period shows a registered entity had 3.65 transactions for each active TFE.

Figure 10 – Average TFE Percentage per Registered Entities with TFE Activity



2. Categorization of the submitted and approved TFE Requests

Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests.

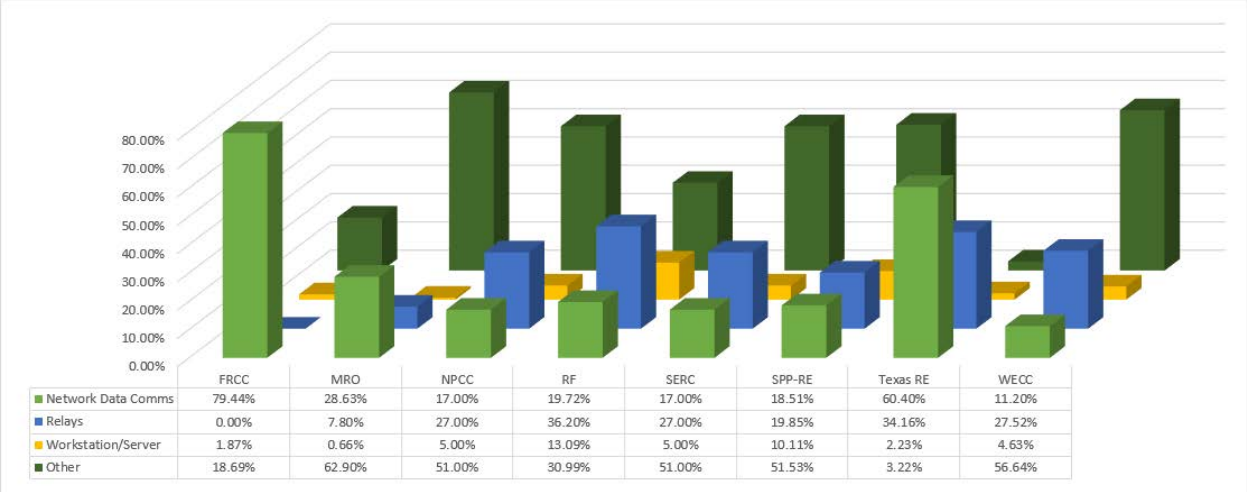
The total number of unique assets subject to TFEs is also decreasing. The decrease is likely due to the system focus of the CIP version 5 standards and the replacement of legacy equipment with more advanced technology with additional capabilities. Currently, TFEs cover 16,704 unique assets across the ERO Enterprise. This number, however, is not necessarily representative as there are two TFEs approved by WECC that account for 7,608 assets, which is almost half the number of total ERO Enterprise assets, and covers nearly 71% of WECC's total covered assets. During its next compliance monitoring engagement with the relevant registered entity, WECC plans to assess

the accuracy of the TFEs in question. In addition, NERC identified a TFE in the Texas RE region with 480 assets, which is over half of the total covered assets for Texas RE. Texas RE plans to review that TFE during its next CIP compliance monitoring engagement with that registered entity where the applicable Standard and requirement are within the audit scope.

Due to these three outlying TFEs, this report will first discuss the data as submitted, then review the trend without these outliers, which is a more accurate depiction of TFE asset status. Further, as in the past, some Regional Entities had difficulty providing data on the category of asset data. As a result, to provide a reasonable view of the data for this report, NERC has averaged the asset categories. In addition, NERC has assigned the number of possible assets per region based on the total number of assets and the ERO Enterprise average for that asset category.

Figure 11 shows the data as submitted, breaking out the asset categories by Regional Entity. There is no consistency across Regional Entities with respect to the largest asset category. For instance, FRCC's major asset category is Network Data Communication devices which covers nearly 80% of the TFE assets, while MRO has nearly 63% of the assets categorized as "Other".

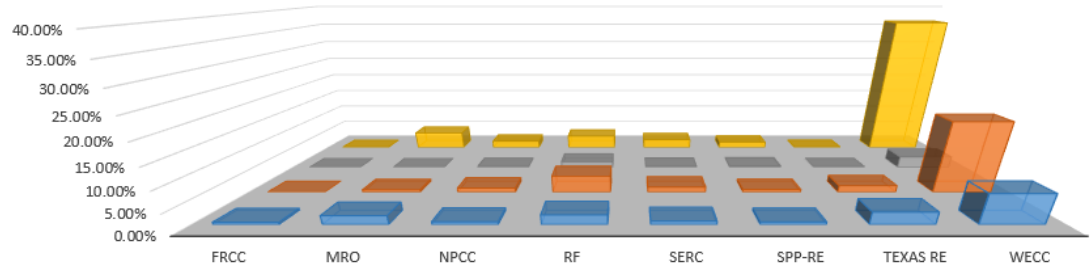
Figure 11 – Percentage of Different Asset Categories within Each Regional Entity



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	Texas RE	WECC
Network Data Comms	79.44%	28.63%	17.00%	19.72%	17.00%	18.51%	60.40%	11.20%
Relays	0.00%	7.80%	27.00%	36.20%	27.00%	19.85%	34.16%	27.52%
Workstation/Server	1.87%	0.66%	5.00%	13.09%	5.00%	10.11%	2.23%	4.63%
Other	18.69%	62.90%	51.00%	30.99%	51.00%	51.53%	3.22%	56.64%

Figure 12 shows the percentage of categories of assets across the ERO Enterprise. Due to the two abnormally large TFEs in WECC, the majority of the asset categories outside of WECC are averaging five percent or less.

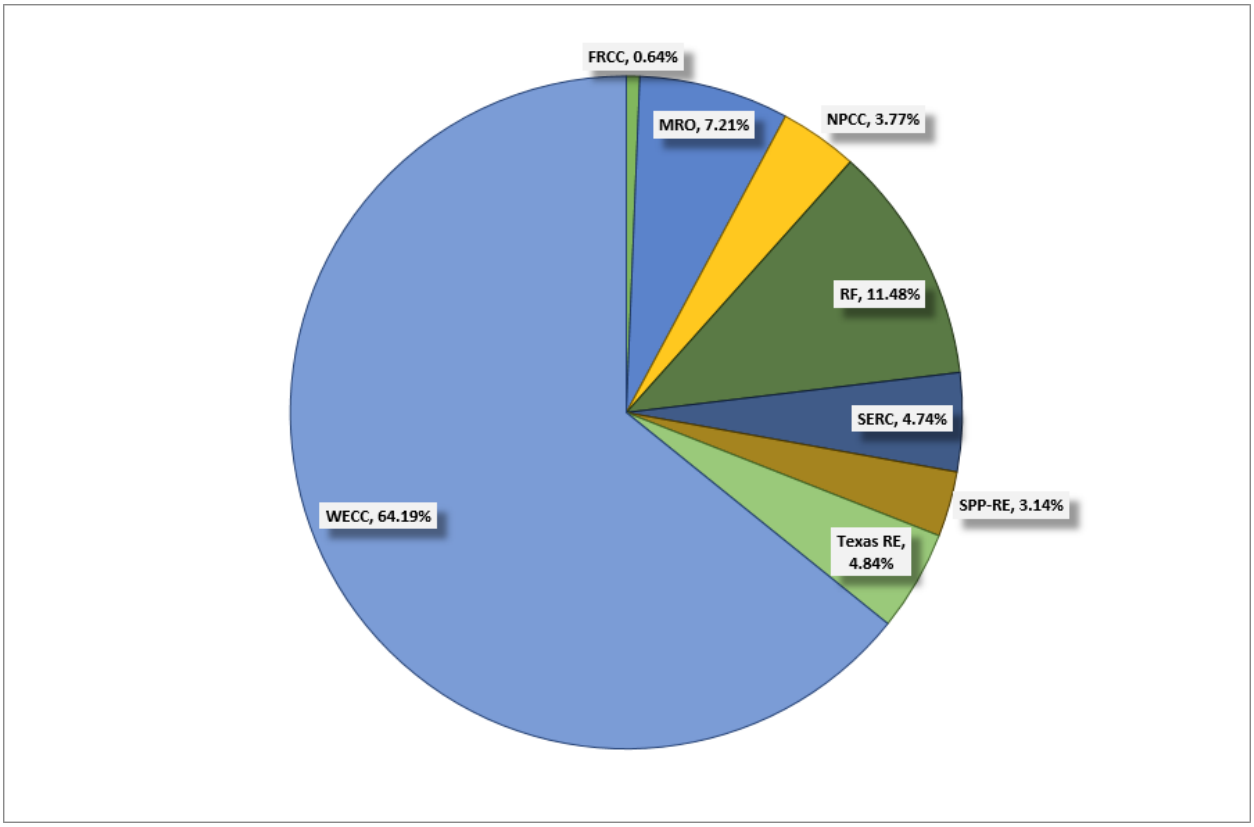
Figure 12 – Percentage of Different Asset Categories Across the ERO



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	Texas RE	WECC
Network Data Comms	0.51%	2.07%	0.64%	2.26%	0.81%	0.58%	2.92%	7.19%
Relays	0.00%	0.56%	1.02%	4.15%	1.28%	0.62%	1.65%	17.67%
Workstations/Servers	0.01%	0.05%	0.19%	1.50%	0.24%	0.32%	0.11%	2.98%
Other	0.12%	4.54%	1.92%	3.56%	2.42%	1.62%	0.16%	36.36%

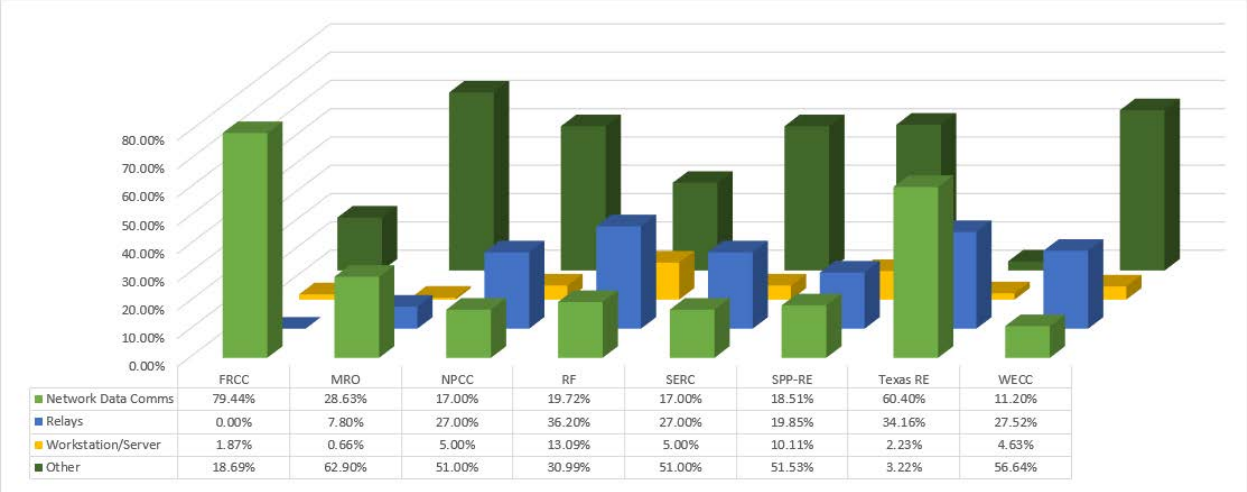
Figure 13 shows the total asset allocation broken out by Regional Entity. The majority of assets covered by TFEs are located within the WECC region due to the two TFEs that account for almost half of the total amount of covered assets. As discussed further below, the report will show the results after eliminating the TFEs with abnormally large assets. The analysis from the data without those three TFEs provides a more accurate analysis of the TFE program.

Figure 13 – Percentage of Assets Covered by TFEs per Regional Entity



The trend changes dramatically when the three abnormally large TFEs are removed from the analysis. The total number of assets being discussed without the three large TFEs is 8,616, which is roughly 52% of the total reported assets. Figure 14 shows the percentage of asset categories by Regional Entity, without the three abnormally large TFEs in the analysis. As shown below, the dynamic of allocation per categories drastically changes compared to Figure 11.

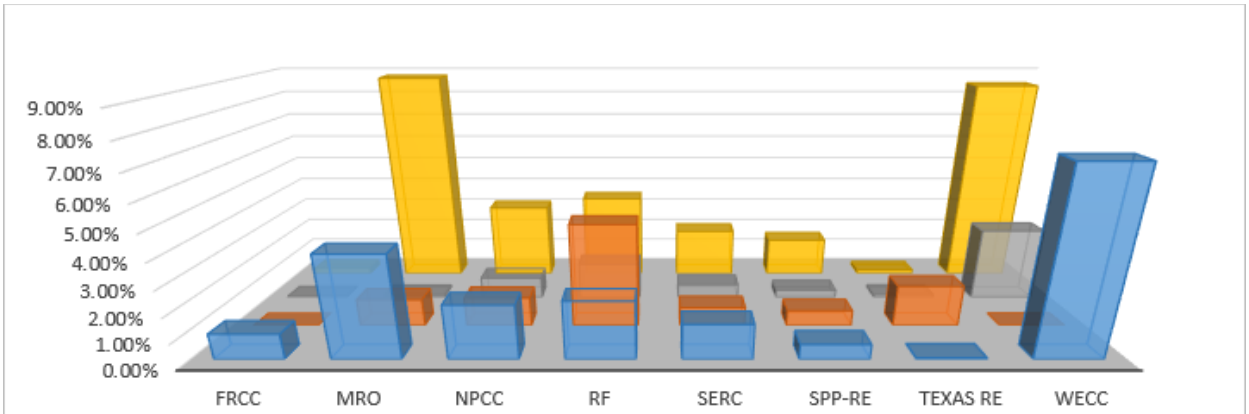
Figure 14 – Percentage of Different Asset Categories within Each Regional Entity Excluding Outliers



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	Texas RE	WECC
Network Data Comms	79.44%	28.63%	17.00%	19.72%	17.00%	18.51%	60.40%	11.20%
Relays	0.00%	7.80%	27.00%	36.20%	27.00%	19.85%	34.16%	27.52%
Workstation/Server	1.87%	0.66%	5.00%	13.09%	5.00%	10.11%	2.23%	4.63%
Other	18.69%	62.90%	51.00%	30.99%	51.00%	51.53%	3.22%	56.64%

Figure 15 shows the breakout of asset categories across the ERO Enterprise, excluding the three outliers. This figure better illustrates where certain issues may lie within the TFE program and, in particular, identify other outlying issues that need further analysis. Compared to Figure 12, Figure 15 shows more breadth of asset categories, consistent with NERC's expectation. There are more assets in the Relay and Workstations/Servers categories. As expected, the category of "Other" contains the majority of assets for most of the Regional Entities.

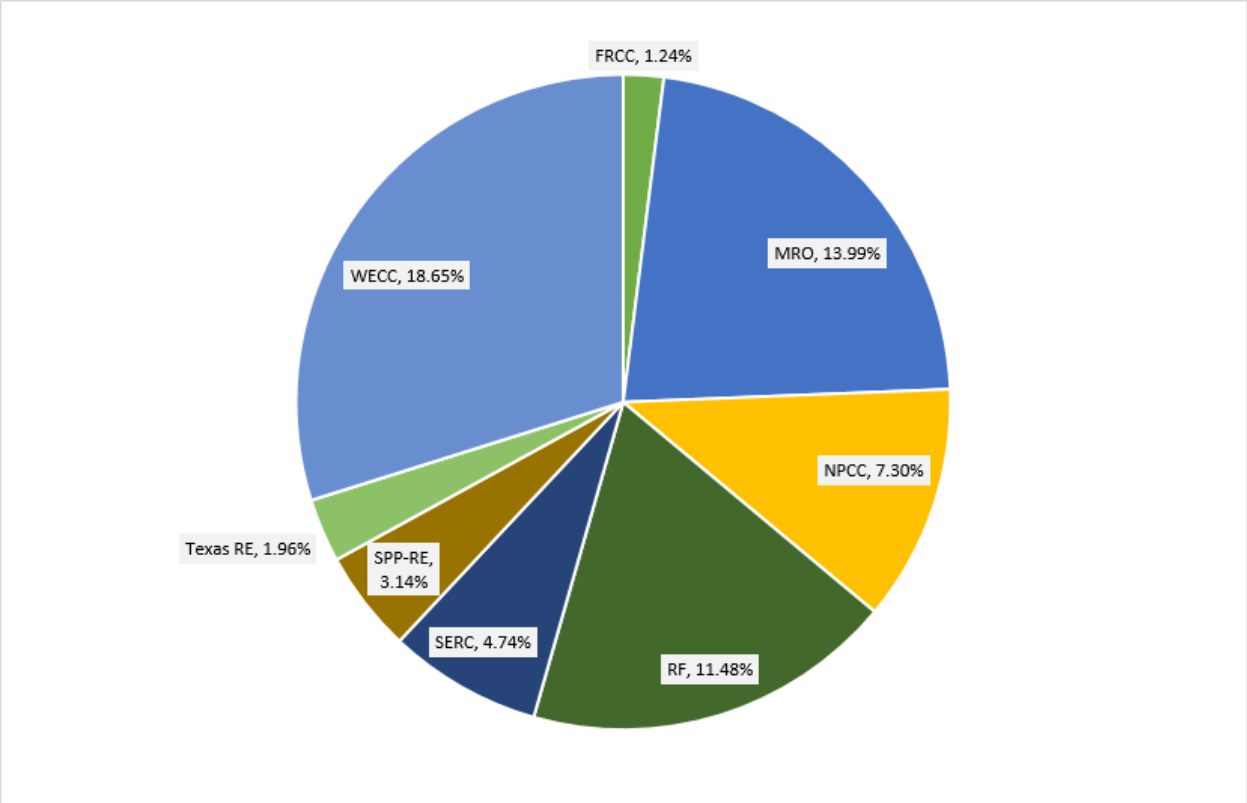
Figure 15 – Percentage of Different Asset Categories Across the ERO Excluding Outliers



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	Texas RE	WECC
Network Data Comms	0.99%	4.00%	2.12%	2.26%	1.37%	0.58%	0.05%	7.19%
Relays	0.00%	1.09%	1.17%	4.15%	0.76%	0.62%	1.65%	0.01%
Workstations/Servers	0.02%	0.09%	0.88%	1.50%	0.57%	0.32%	0.11%	2.98%
Other	0.23%	8.80%	3.14%	3.56%	2.04%	1.62%	0.16%	8.48%

Figure 16 depicts the allocation of assets per Regional Entity, which is drastically different than Figure 13. Figure 16 shows a more equal distribution of assets throughout the ERO Enterprise rather than the majority within WECC. This depiction shows a few abnormalities that were not expected, such as the amount of MRO and SERC's assets. SERC has more registered entities within its region compared to MRO but SERC is showing less than 5% of the assets are covered by TFEs, whereas MRO is showing almost 14%. MRO's percentage is also larger than RF for covered assets. MRO has two TFEs that cover a significant number of assets in their regional footprint and, upon investigation, one registered entity was responsible for both of the TFEs. The registered entity had several applicable transmission substations which increased the amount of assets being covered by TFEs.

Figure 16 – Percentage of Assets covered by TFEs per Regional Entity Excluding Outliers



3. Categorization of the circumstances or justification

Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Registered Entity.

As in the past years, a TFE request tends to be based on one of the first three criteria mentioned below. That pattern remains unchanged for this reporting period. To date, there have been no reports of TFEs that were approved based on the last three criteria:

- Not technically possible
- Operationally infeasible
- Precluded by technical limitations
- Adverse effect on bulk electric system reliability
- Cannot achieve by compliance date

- Excessive cost that exceeds reliability benefit
- Conflicts with other statutory or regulatory requirement
- Unacceptable safety risks

4. Categorization of the compensating measures and mitigating measures implemented and maintained

Categorization of the compensating measures and mitigating measures implemented and maintained by registered entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets.

The ERO continues to evaluate the extent and effectiveness of compensating measures that are described in TFE requests. The majority of compensating and/or mitigating measures are accomplished by compliance with requirements in related CIP Standards. As most TFEs relate to the same types of assets, the registered entities are applying the same mitigation measures for each of the TFEs to address the known risks.

5. TFE rejection or disapproval

For each TFE Request that was rejected or disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the TFE Termination Date was later than the latest date specified in Section 5.2.6, or 9.3, as applicable, a statement of the number of days the Registered Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of Penalties or sanctions pursuant to Section 5.3.

During the reporting period, WECC did not approve four new TFE requests and one TE modification. No other Regional Entity disapproved a new TFE request or a modification. WECC disapproved the requests because the assets covered by the requested TFE were not applicable to the requirement. For instance, in one of the disapproved TFEs, the assets were a part of a medium impact BES Cyber System without External Routable Connectivity and, therefore, the relevant requirement, CIP-007-6 Requirement R5 Part 5.6, was not applicable. During the 2018 reporting period, there were no TFE termination requests that caused the effective date to be extended beyond the latest date specified in Section 5.2.6 or Section 9.3 of Appendix 4D, as applicable.

6. Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures

A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by registered entities in accordance with approved TFEs.

Appendix 4D of NERC's ROP is part of the Compliance Monitoring and Enforcement Program ("CMEP") that forms the framework for Regional Entities to review and audit TFE requests. During a compliance audit, a registered entity with a TFE for a particular requirement is *not* evaluated against the applicable Reliability Standard for which a TFE was accepted and approved, but instead evaluated against the alternative compliance obligations assumed by the registered entity (*i.e.*, compensating and mitigation measures).

All Regional Entities conduct compliance audits where approved or terminated TFEs are in scope. Typically, an audit of a registered entity with TFEs will be managed according to the TFEs that need to be reviewed (*i.e.*, based on factors such as quantity, locations, etc.). Reviews include interviewing subject matter experts specifically about TFEs, and sampling evidence pertaining to a TFE's mitigating and compensating measures, among other things. As was indicated in previous annual TFE reports, Regional Entities continue to report that registered entities are managing and maintaining their TFEs within the procedural requirements of Appendix 4D. Regional Entities have also issued audit findings that identify TFEs to be processed consistent with the CMEP.

7. Assessments of impacts on the reliability of the BES

Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the Wide-Area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented.

The TFE Task Force ("TFETF"), comprised of subject matter experts from each Regional Entity and NERC, reviews TFE requests to verify sufficiency and consistency of the requests. In addition, the TFETF verifies the availability and use of TFEs in lieu of strict compliance. The TFETF reports that the use of TFEs has not had an adverse impact on BES reliability. Regional Entities reported similar experiences with the execution and management of the TFE process and the manner in which it impacted BES reliability. Regional Entities reported that a large majority of registered entities have implemented multiple compensating and mitigating measures for Covered Assets. In general, the mitigating and compensating measures of approved TFEs that were implemented in lieu of strict compliance with applicable CIP Reliability Standards accomplished the stated alternate compliance objective. As a result, the level of BES security achieved through the TFE process is comparable to strict compliance with the applicable Reliability Standards.

8. Efforts to eliminate future reliance on TFEs

Discussion of efforts to eliminate future reliance on TFEs.

In the past, the value of a TFE was the safe harbor it provides to a registered entity when strict compliance to certain Reliability Standards could not be achieved. As referenced in Order No. 706, TFEs are rooted in the problem of legacy equipment and the economic considerations involved in the replacement of such equipment before the end of its useful life.[12] As registered entities increasingly move away from legacy equipment, the value of the TFE program, as currently constructed, is diminishing in comparison to the program's administrative burden. Despite the decrease in the number of active TFEs and the total assets covered by a TFE, the level of effort by the registered entity and Regional Entity necessary to maintain and administer a TFE continues to increase. TFE record-keeping, as currently required by Appendix 4D of the NERC

[12] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").

ROP, is burdensome for the Regional Entities and registered entities alike, creating work efforts that may outweigh any perceived benefit. In addition, CMEP processes that are used to assess general compliance with the CIP Reliability Standards are equally effective in evaluating the compensating and mitigation measures when strict compliance is "technically infeasible."

To that end, NERC and the Regional Entities are considering alternatives to the current TFE program to alleviate the administrative burden on registered entities and the ERO Enterprise. During quarterly meetings, the TFETF has focused on TFE management, administrative processes, and approaches to making the processes more effective and efficient for the Regional Entities and registered entities. The TFETF members concluded that the existing TFE processes are labor intensive and do not mitigate significant risks apart from the application of existing CMEP tools such as Compliance Audits, Spot Checks, Self-Certifications, and Self-Reports. The TFETF has stated that the ERO Enterprise may retain the same awareness and risk mitigation of the TFE program without the administrative burden if the NERC allows the registered entity to maintain the exception without prior approval, provided that the registered entity could demonstrate upon the next compliance monitoring engagement that the exception is reasonable and appropriate mitigation measures are in place to address any residual risk. As NERC considers alternatives to the TFE program, it will consult with Commission staff and request Commission approval for any changes to the NERC ROP.

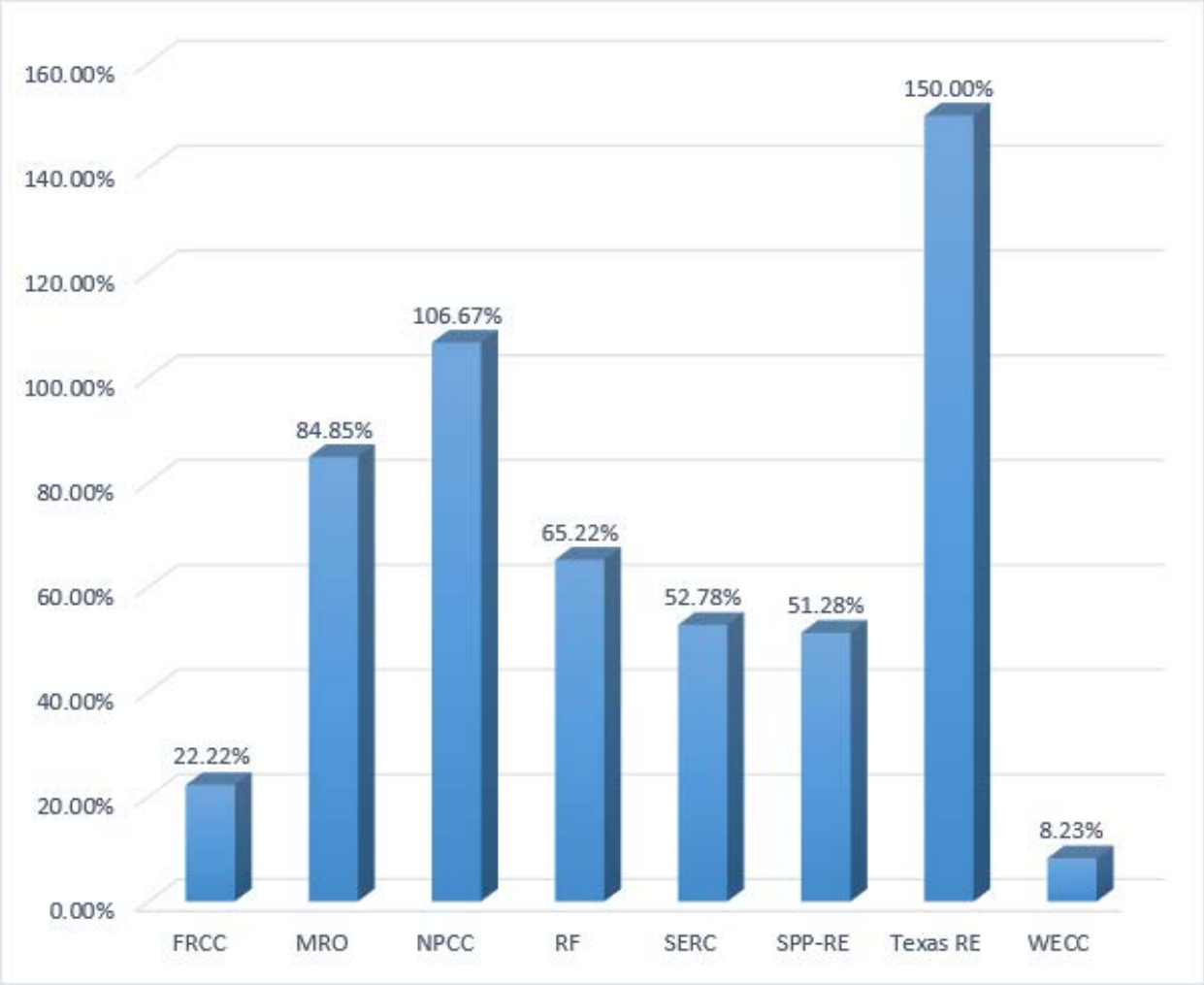
9. Material Change Reports

Data and information regarding Material Change Reports, including the number of Material Change Reports filed annually and information regarding the types of circumstances or events that led to Material Changes, as well as any additional information NERC believes would be useful.

When registered entities modify the information associated with approved TFEs, updates are submitted to the relevant Regional Entity via a "Material Change Report" ("MCR"). An MCR

requires approval by the Regional Entity, which can then refer to current data when undertaking compliance monitoring activities (e.g., Compliance Audits, Spot Checks, Self-Certifications, etc.). Figure 17 below shows the percentage of amendments per active TFEs within each Regional Entity. Most changes are needed for asset count changes and administrative updates. Some Regional Entities have percentages over 100% which means that every approved TFE had more than one MCR.

Figure 17 – TFE Amendments to Active TFEs per Regional Entity



10. Additional information about TFEs and their TFE Expiration Dates

Additional information about TFEs and their TFE Expiration Dates, including the number of TFEs by expiration year and CIP Standard requirement, the percentage of currently

approved TFEs without TFE Expiration Dates, and the number of new TFEs approved without expiration dates annually.

In its September 2013 Order, the Commission directed NERC to provide additional information in the annual TFE reports related to TFEs with and without expiration dates. As reported previously, most TFEs do not have expiration dates.[13] For the next TFE reporting period, July 1, 2018 to June 30, 2019, there are seven TFEs scheduled to be expired. Of these seven, one is applied to CIP-007-6 Requirement R1 Part 1.1, two are applied to CIP-007-6 Requirement R5 Part 5.1, and the other four are applied to CIP-007-6 Requirement R5 Part 5.7. There is one TFE that is scheduled to expire after the next TFE reporting period; it is applied to CIP-005-5 Requirement R2 Part 2.3.

11. Consistency in Review, Approval and Disapproval of TFE Requests

Appendix 4D, Section 11.1 of the NERC ROP requires that NERC and the Regional Entities collaborate to assure "consistency in the review, approval and disapproval of TFE Requests. . . ." Also, as noted above, Section 11.2.4 of the NERC ROP requires that NERC submit with each Annual TFE Report certain information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE requests. The scope document for the TFETF describes activities and deliverables that support this effort:

- Review Regional Entities' processes and performance in administering TFE Requests and Material Change Reports
- Evaluate whether the administration of TFE activities among the Regional Entities yields consistent results
- Assess compensating and mitigating measures described in TFEs for quality and sufficiency
- Review approved and disapproved TFE Requests or Material Change Reports for consistency

[13] September 2013 Order at P 15.

- Monitor active TFEs throughout their life cycle to determine whether they remain necessary and effective

IV. CONCLUSION

For the foregoing reasons, NERC respectfully requests that the Commission accept the 2018 Annual Report.

Respectfully submitted,

/s/ Shamai Elstein

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September 28, 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 28th day of September, 2018.

/s/ Shamai Elstein

Shamai Elstein
Attorney for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 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 regarding Proposed Supply Chain Risk Management Reliability Standards, Docket No. RM17-13-000

Dear Ms. Bose:

On September 26, 2017, the North American Electric Reliability Corporation ("NERC") submitted for Commission approval three Critical Infrastructure Protection ("CIP") Reliability Standards related to supply chain risk management: CIP-013-1 (Cyber Security – Supply Chain Risk Management), CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), and CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments).[1]

On January 18, 2018, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to approve these standards.[2] Among other things, the Commission also proposed to direct NERC to file the interim and final reports requested by the NERC Board of Trustees relating to supply chain risk management issues.[3] In its March 26, 2018 comments on the NOPR, NERC committed to filing the interim and final study reports with the Commission.[4]

Attachment A contains the interim report as it was submitted to the NERC Board of Trustees in advance of its August 16, 2018 meeting.[5] Over the coming months, NERC will continue to study supply

[1] *Petition of NERC for Approval of Proposed Reliability Standards CIP-013-1, CIP-005-6, and CIP-010-3 Addressing Supply Chain Cybersecurity Risk Management*, Docket No. RM17-13-000 (Sept. 26, 2017).

[2] Notice of Proposed Rulemaking, *Supply Chain Risk Management Reliability Standards*, 162 FERC ¶ 61,044 (2018).

[3] *Id.* at P 43.

[4] *Comments of NERC in Response to Notice of Proposed Rulemaking*, at 2, Docket No. RM17-13-000 (Mar. 26, 2018).

[5] The accompanying materials and presentation are available on NERC's website at https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_August_16_2018.pdf (*see* Agenda Item 7.a) *and* https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Presentations_Combined_Board_Meeting_August_16_2018.pdf (presentation).

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chain risks and develop recommendations for follow-up actions. NERC will present the final report to its Board at its February 2019 meeting.

Respectfully submitted,

/s/ Shamai Elstein

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Counsel for North American Electric Reliability Corporation

Attachment: **Attachment A**, *Supply Chain Risk Assessment* (EPRI, July 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 7th day of September, 2018.

/s/ Shamai Elstein

Shamai Elstein

Counsel for the North American Electric Reliability Corporation

Attachment A

Supply Chain Risk Assessment

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Supply Chain Risk Assessment

Final Report

Supply Chain Risk Assessment

Final Report

July 2018

G. Rasche

ELECTRIC POWER RESEARCH INSTITUTE
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ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

G. Rasche

T. Whitney

B. Sooter

Report Title: Supply Chain Risk Assessment: Final Report

KEY RESEARCH QUESTION

The North American Electric Reliability Corporation (NERC) Board of Trustees requested NERC management to "(i)study the nature and complexity of cyber security supply chain risks, including risks associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address any issues identified, and (ii) NERC management provide an interim report to the Board related to the foregoing by no later than approximately 12 months after the adoption of these resolutions and a follow-up final report to the Board no later than approximately 18 months after the adoption of these resolutions." The objective of this project is to provide an independent analysis of these supply chain risks and develop recommendations for how the electric sector can address them.

RESEARCH OVERVIEW

EPRI performed this analysis by executing the following tasks:

1. Performing a Bulk Electric System (BES) product and manufacturer assessment.
2. Analyzing emerging vendor practices and industry standards.
3. Analyzing the applicability of the Critical Infrastructure Protection (CIP) standards to supply chain risks.
4. Developing recommendations for follow-up actions that will best address any issues identified.

KEY TAKEAWAYS

In summary, the analysis performed and documented in this report resulted in three categories of recommendations for further analysis and investigation:

- **Applying industry practices and guides:** EPRI identified 10 emerging practices that if applied effectively could reduce additional supply chain risks.
- **Understanding common-mode vulnerabilities for low-impact BES Cyber Systems (BCS):** EPRI recommended additional research to model and assess the impact of a common-mode exploits targeting multiple, geographically dispersed low-impact BCS to determine the extent of potential risk of a compromise in supply chain.
- **Assessing supply chain risk through data analysis to address the following topics:**
    - Pre-Audit surveys and questionnaires to help identify and assess industry practices
    - Targeted outreach to vendors that support the reliability of the Bulk Electric System
    - Development of standardized vendor supply chain practices
    - Independent testing of legacy applications and products

WHY THIS MATTERS

Modern industrial control systems, such as those in the electric power industry, have become more sophisticated and complex to deliver better services, deliver more cost-competitive products, and provide greater end-to-end, responsive control. With this evolution has come an increase in the complexity of the industrial supply chain and as well as additional interdependencies across suppliers and service providers. Managing the associated cyber security risks is critical for ensuring the reliability of the bulk electric system.

HOW TO APPLY RESULTS

This report identifies current supply chain risks for the bulk electric system and provides objective, technical recommendations to industry for mitigating risks as well as identifying areas for further analysis. The results may be used to examine current supply chain security processes and requirements to identify opportunities to reduce cyber security risk.

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1
INTRODUCTION AND BACKGROUND

According to a July 20, 2017 New Jersey Cybersecurity and Communications Integration Cell (NJCCIC) report, "The NJCCIC assesses with high confidence that capable threat actors—both politically-motivated state actors and their proxies, as well as profit-driven criminals—will increasingly leverage supply chain compromises to conduct network intrusions and attacks. These incidents could result in the exfiltration, manipulation, or destruction of data and disruption to daily operations and business continuity" [1]. The difficulty of monitoring a supply chain that may include dozens of suppliers at multiple transaction levels is compounded by a lack of standardization or security integration between suppliers and buyers.

The root cause of escalating supply chain vulnerabilities lies in the increasing dependence on microelectronics, computer networks, and telecommunications. Modern industrial control systems, such as those in the electric power industry, have become more sophisticated and complex to deliver better services, deliver more cost-competitive products, and provide greater end-to-end, responsive control.

The enabling technologies for modernizing the electric power industry include some of the following infrastructure components:

- Hardware endpoint devices, system monitors, remote switches, and next-generation SCADA/remote telemetry units (RTU) based on programmable logic circuit (PLC), synchronous link control (SLC), and ASIC-based (application-specific integrated circuit) devices.

- Software for detecting and correcting errors in a power grid system, SCADA/ICS/RTU control and monitoring, PLC/SLC software interfaces, telecommunication/networking transports, and power system troubleshooting and analysis software tools.

On August 10, 2017, the NERC Board of Trustees approved the proposed Supply Chain Risk Management requirements: Cyber Security – Supply Chain Risk Management – CIP-005-6, CIP-010-3, and CIP-013-1. As part of the approval, the Board proposed additional resolutions for NERC to undertake [2].

The NERC Board of Trustees requested that NERC management "study the nature and complexity of cyber security supply chain risks, including risks associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address any issues identified, and (ii) NERC management provide an interim report to the Board related to the foregoing by no later than approximately 12 months after the adoption of these resolutions and a follow-up final report to the Board no later than approximately 18 months after the adoption of these resolutions."

The objective of this project is to support NERC in the development of its interim report through the following tasks:

1. Perform BES product and manufacturer assessment.

2. Analyze emerging vendor practices and industry standards.
3. Analyze the applicability of the critical infrastructure protection (CIP) standards to supply chain risks.
4. Develop recommendations for follow-up actions that will best address any issues identified.

2
MARKET DATA ASSESSMENT

The research activities under this task consist of assessing the product/manufacturer types used on the BES for the following areas: SCADA/control systems, network and telecommunications, and operating systems. The details of the market research market share data are from the following sources:

- Newton-Evan Research Company
- Other sources as sited in the References section of this report

By analyzing the numbers and comparing that data with the systems that are most likely tied to real-time applications as referenced in the NERC BES Cyber Asset Survey [3], the data provides insight as to the systems being currently[1] procured by asset owners and operators.

Market Share of Substation Networking Equipment

Although there appears to be a wide array of substation network equipment being purchased, half of the market share is held by only two vendors [redacted] Further, [redacted] has a 55% world-wide enterprise network market share in the corporate environment of many industries in addition to the electric power industry.

Figure 2-1
Substation communication equipment

[1] Newton-Evan Research Company research data is for equipment purchased in 2017.

Market Share of Operating Systems

The operating system used to govern BES Cyber Systems usually dictates the type of threats and vulnerabilities to which the systems are exposed. Based on the data, [redacted] has an 87% market share.

As asset owners and operators develop their plans to manage supply chain risk it will be imperative that they give strong consideration to the high prevalence of systems that depend on a relatively small number of vendors and to determine the best means to address vendors that have a stake in their operations. However, asset owners and operators may find it more difficult to negotiate unique, industry-oriented or asset owner-oriented terms and conditions within procurement contracts with large multinational vendors. Unique terms may drive up product costs or cause delays in the procurement processes.

Figure 2-2
Operating systems

Market Share of Energy Management Systems

The energy-management system (EMS) platform is widely regarded as one of the most critical systems on the bulk electric system. If misused, it could result in significant damage to transmission equipment and potentially lengthy outages.

In general, EMS vendors have core customers that are primarily within the critical infrastructure sector, which means that from a supply chain risk management perspective, the electric power industry can expect reasonably responsive terms when negotiating security in comparison to vendors that may not have a primary focus in critical infrastructure. Another consideration is the limited variety of vendors that offer solutions in this category. If a vulnerability is introduced

into a critical supply chain within the system development lifecycle of one of the core vendor's in this category, the result could be significant to the reliability and security of the BES.

Figure 2-3
EMS vendors

Market Share of Remote Terminal Units

Remote terminal units (RTUs) are microprocessor-based devices that often perform the critical role of sending telemetry and control signals between field devices and supervisory control and data acquisition (SCADA) systems. An observation of note would be the variety of vendors in this category. No single vendor exceeds 20% market share, which is an indicator that a threat to the supply chain of SCADA systems would have a lower impact than that of the aforementioned categories.

Figure 2-4
RTU vendors

3
ANALYZING VENDOR PRACTICES AND INDUSTRY STANDARDS

The research activities in this task consist of analyzing emerging best practices and standards used in other industries to mitigate supply chain risks. A key aspect of mitigating supply chain risk is ensuring that each of the product and service providers adhere to best practices and standards in security. Ultimately, it is the responsibility of both the purchaser and supplier to ensure that their security concerns are understood and that practices to mitigate risk are established. The CIP standards are designed to manage supply chain risk and consist of three core supply chain concepts:

- Development and implementation of plans and policies to manage supply chain risk (CIP-013-1)
- Testing and validation of software (CIP-005-6)
- Monitoring and control of vendor connections to BES Cyber Systems (CIP-010-3)

Although there are numerous security practices and guides applicable to many aspects of operation and information technology, this report focuses on specific standards, vendor practices, and guidelines for mitigating the risks shared by the purchaser and supplier of technologies and services. The most relevant supply chain practices and standards are referenced in Appendix B (including practices currently not considered in the scope of the CIP standards). Based on research performed on each standard or reference in Appendix B, several noteworthy approaches were identified.

1. Off-premise Supplier Services

In the scenario, where a supplier performs services for an entity involving BES Cyber Assets that are not on the Registered Entity's premises, the FedRAMP standards provide assurance to government entities and suppliers, such as cloud service providers. The ISO/IEC 27017, "Security techniques — Code of practice for information security controls based on ISO/IEC 27002 for cloud services," specifies various requirements that recognize that cloud services are a type of supply chain risk. The following is stated in ISO/IEC 27017 regarding a way to address the risk of cloud service providers:

> *Cloud service customers and cloud service providers can also form a supply chain. Suppose that a cloud service provider provides an infrastructure capabilities type service. In addition, another cloud service provider can provide an application capabilities type service. In this case, the second cloud service provider is a cloud service customer with respect to the first, and a cloud service provider with respect to the cloud service customer using its service. This example illustrates the case where this Recommendation | International Standard applies to an organization both as a cloud service customer and as a cloud service provider. Because cloud service customers and cloud service providers form a supply chain through the design and implementation of*

the cloud service(s), clause "15.1.3 Information and communication technology supply chain" of ISO/IEC 27002 applies."

Although ISO/IEC 27017 is not widely adopted now, if asset owners and operators decide to move certain aspects of their operation off-premise, they should be aware of FedRAMP and the ISO/IEC 27017 standards.

2. Third-Party Accreditation Processes

Suppliers that provide products to various customers may use accredited standards that are independently verified. Standards such as FedRAMP, ISO9001, and ISO27001 use independent third parties to assess their adherence to established standards. The entities that are acquirers or purchasers of companies that have received accreditation may rely on the work of the independent auditors to manage supply chain risks. Currently, neither the CIP standards nor the NERC Rule of Procedures allow for vendors or suppliers (non-Registered Entities) to be audited via NERC or the Regional Entities. In the context of CIP compliance, a supplier or vendor may be audited only if they operate a CIP-applicable asset, but the audit results are applicable to only the Registered Entity. The Regional Audit reports are not provided to any entity other than the Registered Entity that is directly involved in the audit. It is worth consideration to determine methods to share the results of auditing vendor security with Registered Entities to address compliance to the CIP standards supply chain risk management. This concept is currently contemplated and encouraged in APPA's *Managing Supply Chain Risk-Best Practices for Small Entities* [4].

3. Secure Hardware Delivery

Many BES Cyber Assets purchased and deployed on the Bulk Electric System are hardware appliances that are configured to perform very specific real-time functions. The programming is often coupled tightly with the physical operation of the device. In those cases, it might be easy to overlook these types of appliances in the context of supply chain risk management. Appliances such as remote terminal units, switches, relays, or other intelligent electronic devices may not seem like software applications, but they often possess code that can be manipulated in a manner that causes them to misoperate in and potentially affect the BES. Recognizing this risk, the Energy Sector Control Systems Working Group (ESCSWG) that developed the Cybersecurity Procurement Language for Energy Delivery Systems identified controls for hardware delivery to help reduce the risk of compromise during transport:

3.6.1. The Supplier shall establish, document, and implement risk management practices for ICT supply chain delivery of hardware, software, and firmware. The Supplier shall provide documentation on its: • Chain-of-custody practices • Inventory management program (including the location and protection of spare parts) • Information protection practices • Integrity management program for components provided by sub-suppliers • Instructions on how to request replacement parts • Maintenance commitment to ensure that for a specified time into the future, spare parts shall be made available by the Supplier. The Supplier shall use trusted channels to ship critical energy delivery system hardware, such as U.S. registered mail.

4. Provenance

As referenced in NISTIR 7622, NIST 800-161, and other guidelines, provenance, or the ability to provide traceability in the supply chain processes and supplier relationships, improves transparency and improves vendor assessment processes. Provenance is described in NIST 7622 as follows:

Acquirers and their system integrators should maintain the provenance of systems and components under their control to understand where the systems and components originated, their change history while under government control, and who might have had an opportunity to change them. Provenance allows for changes from the baselines of systems and components to be reported to specific stakeholders. Creating and maintaining provenance within the ICT supply chain helps government agencies to achieve greater traceability in case of an adverse event and is critical for understanding and mitigating risks.

The concept of provenance is a central to concept of supply "chain" practices because each link or step in the supplier's process is provided within its provenance documentation. Some challenges with provenance controls may include the following:

- Clarity regarding what constitutes a component with a system
- Ambiguity regarding the authority which has the ability to enforce provenance controls
- Given the limited number of Bulk Electric System vendors in certain market categories, provenance requirement may have diminishing value, due to similarity of supply chains for various entities being supplied by the same vendor

5. Threat Modeling

Threat modeling as described by the IEC 62443-4-1 Secure Product Development Life-Cycle Requirements is "…a process shall be employed to ensure that all products shall have a threat model specific to the current development scope of the product…" This ensures the risk of procurement of any application or systems is appropriately weighed against the risk of compromise to the overall health of the organization or the Bulk electric System. EPRI applied part of its risk management and supply chain guidance, Technical Assessment Methodology[2], from the threat modeling concept. For instance, if an entity was procuring a new remote access system to its medium-impact substations, the threat model should reflect the impact of the remote access system's effect to the BES, and the requirements for that purchase should be applied according to its elevated risk and system-specific vulnerabilities.

6. Assessing Supply Chain Deficiencies

NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition, Section SA-12 (15) states:

[2] https://www.epri.com/#/pages/product/3002008023/?lang=en

The organization establishes a process to address weaknesses or deficiencies in supply chain elements identified during independent or organizational assessments of such elements.

Clearly addressing the controls for identifying and mitigating the risk of assessed vulnerabilities or inherent weaknesses in the supply chain process of certain product or service providers is an important risk management approach. By using this method of mitigating risk by identifying key process deficiencies, asset owners and operators may decrease their supply risk by implementing timely organizational assessments.

7. Recognizing External Dependencies

The Department of Energy's Cyber Security Capabilities Maturity Model (C2M2) highlights manners to assess the effectiveness of various security processes within utility organizations. One aspect considered by the C2M2 is considering supply chain as a process of identifying and managing external dependencies. Recognizing dependencies and those that are most critical to operations can improve the entity's ability to highlight and mitigate supply chain risks. The C2M2 adds:

Supply chain risk is a noteworthy example of a supplier dependency. The cybersecurity characteristics of products and services vary widely. Without proper risk management, they pose serious threats, including software of unknown provenance and counterfeit (possibly malicious) hardware. Organizations' requests for proposal often give suppliers of high-technology systems, devices, and services only rough specifications, which may lack adequate requirements for security and quality assurance.

8. Policy for Handling Supplied Products or Services That Do Not Adhere to Procurement Processes

The U.S. Nuclear Regulatory Commission (NRC) identified processes to manage supplier risks. In its standard, the NRC considered a control to mitigate risks when products or services are supplied that do not adhere to supply chain policies. The NRC recognizes that companies may introduce third-party supplied systems that may not fully adhere to policy but still provides a transparent method to mitigate risks in those events. The NRC states the following in Appendix B, Part 50, Article XV:

Measures shall be established to control materials, parts, or components which do not conform to requirements in order to prevent their inadvertent use or installation. These measures shall include, as appropriate, procedures for identification, documentation, segregation, disposition, and notification to affected organizations. Nonconforming items shall be reviewed and accepted, rejected, repaired or reworked in accordance with documented procedures.

9. Unsupported or Open-Sourced Technology Components

Although the grid is constantly being modernized by the addition of various technologies, there are still legacy systems that are not supported by a vendor. In these cases, it does not mean the supply chain risk management plan is not applicable to these systems. Instead, different processes must be considered to effectively mitigate their risk while updating systems or system

components during the end-of-life phase of the product. NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition states the following regarding unsupported system components:

> *The organization: a. Replaces information system components when support for the components is no longer available from the developer, vendor, or manufacturer; and b. Provides justification and documents approval for the continued use of unsupported system components required to satisfy mission/business needs.*

The concept of replacing or developing a plan for an unsupported system or system components is a vital aspect of grid security. Currently CIP-007's Patch Management requirement does not mandate that any compensating controls are implemented when a patch source is not available (i.e. the system is no longer supported). If these systems are left unchecked, significant risk could remain unmitigated on the BES.

Related to products that are not supported by the vendor, many products are based on open sourced applications. The Open Group[3] created a set of standards and certification processes titled the "Open Trusted Technology Provider™ Standard (O-TTPS) Certification Program." The O-TTPS standard identifies several supply chain-related controls for purchasers. One of its standards addresses open-sourced providers and requires the following in Section 4.2.1.10 of the O-TTPS and ISO/IEC 20243:2015:

> *In the management of Open Source assets and artifacts, components sourced shall be identified as derived from well-understood component lineage.*
>
> *In the management of Open Source assets and artifacts, components sourced shall be subject to well-defined acceptance procedures that include asset and artifact security and integrity before their use within a product.*
>
> *For such sourced components, responsibilities for ongoing support and patching shall be clearly understood.*

10. Concluding Supplier Relationships

An important aspect of managing suppliers is knowing how to terminate relationships with third parties in manner that limits the operational impact of losing the product or service. The UTC's "Supply Chain Risk Management for Utilities" paper highlights approaches that utilities can consider when concluding the supplier relationship. On page 13, it states the following:

> *[U]tilities need to be very conscious of organizing supplier relationship termination processes that minimize security risks after the relationship is completed. Specifically, utilities should ensure that the ending of a relationship with a supplier that involves a transition between different suppliers or from a supplier to the utility involves an organized transition plan where the current supplier's responsibilities and activities are assumed by the receiving party.*

[3] https://ottps-cert.opengroup.org/

4
COMPARING MARKET DATA AND PRACTICES TO THE CIP SUPPLY CHAIN STANDARDS

The research activities in this task consist of analyzing the results of the market assessment in Task 1 to compare the supply chain risk of different categories of NERC applicable systems such as:

- High and Medium Impact BES Cyber Systems (BCS)
- Electronic Access Control or Monitoring Systems (EACMS)
- Physical Access Control Systems (PACS)
- Low Impact BES Cyber Systems (BCS)

Applicability of the Supply Chain Standards to the Bulk Electric System

The CIP Standards are applicable to three categories of assets on the Bulk Electric System (BES): high, medium, and low. The *high* and *medium* impact categories have the most requirements, while *low* impact has the least. The Supply Chain Standard (CIP-013-1) is applicable to high and medium impact categories BES Cyber Systems only. Figure 4-1 (created from data supplied by NERC) shows that roughly 21% of the BES, or 270 Registered Entities, have either high or medium impact BES Cyber Systems. The remaining 79% of the assets, or 992 Registered Entities, are low impact and are not applicable to the supply chain requirements.

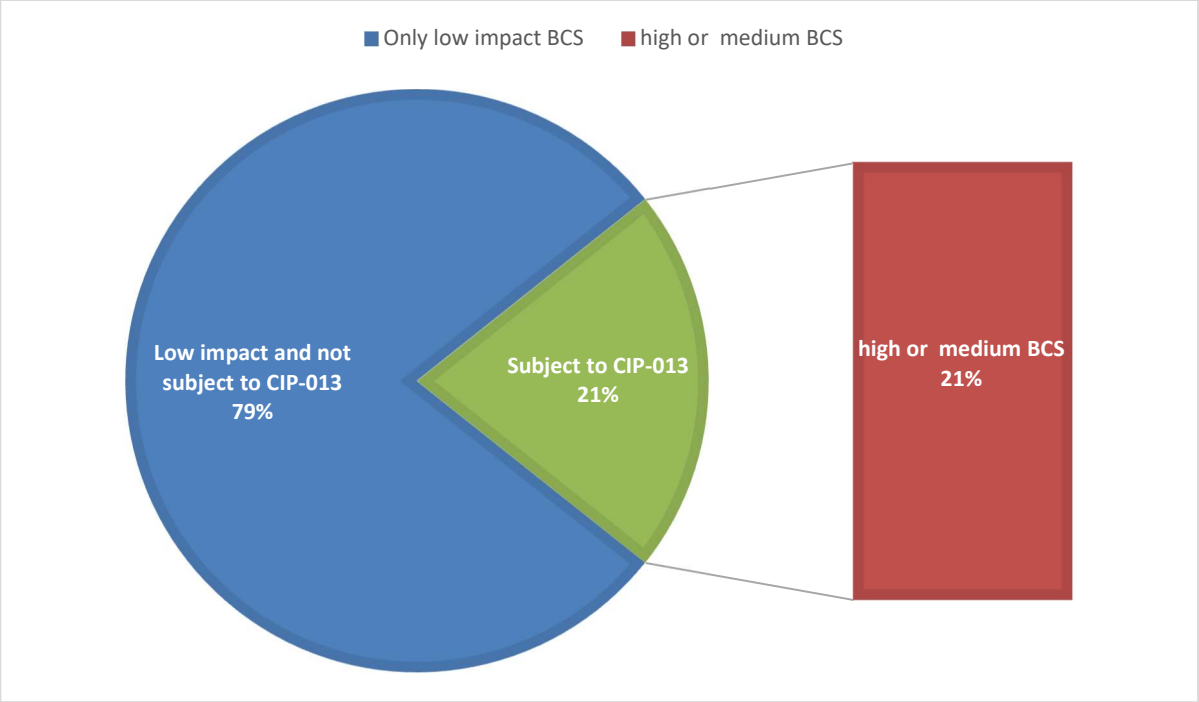

Figure 4-1
1262 Registered Entities have BCS

Understanding the Risk Basis of the CIP Standards

The CIP Standards employ an asset-centric, risk-based approach to securing the BES. This approach requires systems or facilities that have the highest impact to the grid receive the highest level of protections. Conversely, the lowest impact categories receive the fewest security requirements. This concept may mitigate the risk of threat actors targeting specific assets or electric power entities because of their potential impact to the grid. Threats originating from supply chain vulnerabilities, however, may challenge this asset-centric approach. If a major vendor with sizeable market share unintentionally supplies a compromised product to a sizeable percentage of the industry, the impact to the reliability of the BES could be significant because the vendor may supply hundreds of products at all impact categories. This type of compromise may result in the aggregate risk of misuse to numerous low impact BES Cyber Systems, which could potentially equal the impact of the compromise of any single high or medium impact BES Cyber System. This type of risk is described as a "common-mode vulnerability," where a single configuration-based vulnerability reaches exposure to large quantities of similarly configured devices. Many risks associated with cyber threats have common-mode vulnerabilities. Virus, worms, and malware programs work in this manner. Given that 79% of the Registered Entities possessing BES cyber systems are not applicable to the supply chain standard, future assessments of the effectiveness of requirements related to the supply chain should be considered to evaluate how well the supply chain requirements have a "trickle-down" effect into the low-impact categories of BES Cyber Systems.

Supply Chain Risk Considerations for CIP Applicable Assets

While the Supply Chain requirements are applicable to high and medium BES Cyber Systems, they are currently not applicable to all types of CIP applicable systems within the high- and medium-impact categories. Table 4-1 summarizes the applicability of the supply chain standards based on the various CIP asset categories. Blue boxes indicate that the asset category is subject to the referenced standards. The white boxes are not subject to the referenced standards.

Table 4-1
CIP Asset Categories

Requirement	CIP-013-1	CIP-005-6 R2.4	CIP-010-3 R1.6
High Impact BES Cyber Systems			
High Impact Protected Cyber Asset			
High Impact Physical Access Control Systems			
High Impact EACMS			

Medium Impact BES Cyber Systems			
Medium Impact Protected Cyber Asset			
Medium Impact Physical Access Control Systems			
Medium Impact EACMS			

Processes-Based Procurement Requirements

The supply chain requirements are applicable to BES Cyber Systems at the high and medium impact categories. CIP-013-1 requires the following:

> *R1: Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. The plan(s) shall include:*
>
> > *1.1. One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).*
> >
> > *1.2. One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:*
> >
> > > *1.2.1. Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*
> > >
> > > *1.2.2. Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*
> > >
> > > *1.2.3. Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;*
> > >
> > > *1.2.4. Disclosure by vendors of known vulnerabilities related to the products or services provided to the Responsible Entity;*
> > >
> > > *1.2.5. Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and*
> > >
> > > *1.2.6. Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).*

R2: Each Responsible Entity shall implement its supply chain cyber security risk management plan(s) specified in Requirement R1.

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

It is important to note that the standard is not stating that every BES Cyber System should be procured in a certain manner with specific controls. Rather, the standard is requiring Registered Entities to institute processes in the procurement function to ensure the required elements are being addressed by their vendors. While the standard is only applicable to asset owners that have BES cyber systems at high and medium impact categories, the supply chain processes can easily be ported to all applicable asset types that may have an impact on the Bulk Electric System. The asset categories that are not included in the scope of the Supply Chain requirements are EACMS, PACS, and Protected Cyber Assets (PCAs).

PCAs are difficult to assess their risk generically. PCAs are often servers or networking equipment that resides on the same network as BES Cyber System. From a procurement language perspective, negotiating supply chain security requirements would be highly dependent on the system in question and its risk to other BES Cyber Systems. Entities may need to assess the risk of PCAs on a case-by-case basis to determine whether procurement processes are needed to mitigate the risk of associated BES cyber systems.

The systems that make up EACMS and PACS often are the systems used to secure and monitor the most critical systems on the BES. These types include firewalls, routers, switches, intrusion-detection systems, log monitors, and access control systems. Depending on specific configurations, EACMs or PACS systems—if compromised, misused or rendered unavailable—could have a real-time impact on the reliability and security of the bulk electric system. For instance, if a firewall used to protect BES Cyber Systems within an Electronic Security Perimeter (ESP) was compromised due to supply chain vulnerability, each system within the ESP could be exposed due to its logical proximity to the compromised firewalls. This scenario is common among many of the EACMS types of assets, therefore Registered Entities—regardless of impact level or CIP applicable asset type—should consider applying the same process-based controls to procurement processes uniformly across various cyber assets.

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SUMMARY AND ANALYSIS OF CONCLUSIONS

In summary, the analysis performed and documented in this report concluded three categories of recommendations for further analysis and investigation:

- Applying industry practices and guidelines.
- Mitigating the risk of common-mode vulnerabilities for low-impact BES Cyber Systems.
- Assessing risk through data analysis.

Applying Industry Practices and Guidelines

Section 3 identified noteworthy techniques that are not required by the CIP standards. While the CIP standards addresses many fundamental elements of effective processes to manage the risk of a supply chain, the following four noteworthy approaches, if applied correctly, can reduce residual supply chain risks:

- Third-Party Accreditation Processes – verifying that standardized processes and measures were achieved to mitigate supplier risks.
- Secure Hardware Delivery – protecting hardware and software during physical transport.
- Threat-Informed Procurement Language – tailoring security specifications to the specific risk of the purchaser's environment.
- Unsupported or Open-Sourced Technology Component Processes – to mitigate residual risks for patch/vulnerability management processes for unsupported systems.

Using Supply Chain Controls to Mitigate Common-Mode Vulnerabilities

In conclusion, the existing CIP Supply Chain standards require entities that possess high and medium impact BES Cyber Systems to develop processes to ensure that supply chain risks are being managed through the procurement process. The supply chain standards will be applied to the highest-risk systems that have the greatest impact to the grid. Additional consideration may need to be given to processes to ensure that vendors and entities are applying techniques to mitigate supply chain risk to lower impact levels. Risks of common-mode vulnerabilities, as described in Section 4, can be mitigated if supply chain security practices are applied uniformly across cyber asset types. Uniform application of supply chain security practices may also mitigate the risk of EACMS and PACS vulnerabilities. To more fully assess the risk of common-mode vulnerabilities and the CIP standards, the following points of analysis should be considered:

- Identify the types and quantities of vendor-supplied products used as BES Cyber Systems.

- Research and model the impact of a common-mode exploits targeting multiple, geographically dispersed low-impact BCS to determine the extent of potential risk.
- Direct, targeted outreach to those vendors that have the largest potential risk to the grid irrespective of BES Cyber System impact level.

Going Forward: Assessing the Risks Through Data Analysis

Although the standard has not been approved by FERC during the time of this study, EPRI identified methods to obtain additional information for future evaluation, so that prior to any changes in regulatory policy, data can be obtained, assessed, and discussed in a transparent manner. The following information-gathering methods should be considered to address the recommendations included in this report:

- **Pre-Audit Surveys and Questionnaires to Help Identify and Assess Industry Practices** – Voluntary efforts to obtain risk data in the preliminary stages of Compliance, Monitoring & Enforcement Program activities can be used to obtain information about the (1) installed base of systems used on the BES, (2) procurement language in contracts negotiated with key vendors, and (3) data describing which CIP applicable systems have benefited from procurement language stemming from the CIP supply chain standards.
- **Targeted Outreach to Vendors that Support the Reliability of the Bulk Electric System** – Based on the Market Data Assessment performed in Section 2, various vendors support the secure operations of the BES. Next steps should consider coordinated outreach to vendors that have a high market share of supplied products and services to the BES to ensure that they have awareness to their products' potential impact to reliability and their customer's responsibility to meet the rigor required by the CIP standards. It is encouraged that industry work with their vendor points of contacts to ensure that technical and contractual considerations are addressing the CIP standards.
- **Development of Standardized Vendor Data Sheets** – One of the challenges identified during the analysis of information used to prepare this report was the availability of vendor supply chain practices. EPRI encourages the work of the Critical Infrastructure Protection Committee to develop an open letter to vendors about the CIP standards and recommends that further consideration be given to the creation of a standardized method to provide product and supply chain security facts and features regarding vendor capabilities to help mitigate supply chain risks.
- **Independent Testing of Legacy Applications and Products** – As discussed in NERC's plan to address supply chain risks, partnerships with independent organizations used to test and communicate product vulnerabilities used on the bulk-electric systems will be a key activity going forward. Understanding known vulnerabilities of the installed base will support the industry's effort to become more effective in negotiating contracts and resolving security issues in the procurement of upgraded and implementations of green-field system.

6
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A
APPLICABLE STANDARDS

Standard Name/Reference	Description/Topic	Notable Content
Federal Risk and Authorization Management Program (FedRAMP)	A government-wide program that provides a standardized approach to security assessment, authorization, and continuous monitoring for cloud products and services.	3PAOs play a critical role in the FedRAMP security assessment process, as they are the independent assessment organizations that verify cloud providers' security implementations and provide the overall risk posture of a cloud environment for a security authorization decision. These assessment organizations must demonstrate independence and the technical competence required to test security implementations and collect representative evidence. 3PAOs must: § Plan and perform security assessments of CSP systems § Review security package artifacts in accordance with FedRAMP requirements
ISO9001: Quality Management Systems	Specific sections of the standard contain information on topics such as: • Requirements for a quality management system, including documented information, planning and determining process interactions • Responsibilities of management • Management of resources, including human resources and an organization's work environment • Product realization, including the steps from design to delivery • Measurement, analysis, and improvement of the QMS through activities like internal audits and	3rd party accreditation process and independent verifications of entities.

Standard Name/Reference	Description/Topic	Notable Content
	corrective and preventive action	
ISO/IEC 27017 Information Security Management Systems	Security techniques – Code of practice for information security controls based on ISO/IEC 27002 for cloud services.	Section 4.2: “Cloud service customers and cloud service providers can also form a supply chain. Suppose that a cloud service provider provides an infrastructure capabilities type service. In addition, another cloud service provider can provide an application capabilities type service. In this case, the second cloud service provider is a cloud service customer with respect to the first, and a cloud service provider with respect to the cloud service customer using its service. This example illustrates the case where this Recommendation | International Standard applies to an organization both as a cloud service customer and as a cloud service provider. Because cloud service customers and cloud service providers form a supply chain through the design and implementation of the cloud service(s), clause "15.1.3 Information and communication technology supply chain" of ISO/IEC 27002 applies.”
ISO/IEC 20243 Open Trusted Technology ProviderTM Standard (O-TTPS) -- Mitigating maliciously tainted and counterfeit products	A standard of The Open Group, provides a set of guidelines, recommendations and requirements that help assure against maliciously tainted and counterfeit products throughout commercial off-the-shelf (COTS) information and communication technology (ICT) product lifecycles. *Mitigating Maliciously Tainted and Counterfeit Products*) that addresses supply-chain security and secure engineering.	Open Source Handling *4.2.1.10*- Open Source components are managed as defined by the best practices within the O-TTPS for Product Development/ Engineering methods and Secure Development/Engineering methods. The O-TTPS is an open standard containing a set of organizational guidelines, requirements, and recommendations for integrators, providers, and component suppliers to enhance the security of the global supply chain and the integrity of commercial off-the-shelf (COTS) information and communication technology (ICT).

Standard Name/Reference	Description/Topic	Notable Content
Energy Sector Control Systems Working Group (ESCSWG) - Cybersecurity Procurement Language for Energy Delivery Systems	DOE sponsored guidance documented focused on two areas: • The cybersecurity-related procurement language in this document is intended for use by Acquirers, Integrators, and Suppliers. • The procurement language presented in this document is not intended to be inserted (or attached) directly or verbatim into a procurement contract. The Acquirer and Supplier will need to involve their respective contracting offices in selecting and customizing their procurement contract language.	Section 3.6 Secure Hardware Delivery – 3.6.1. The Supplier shall establish, document, and implement risk management practices for ICT supply chain delivery of hardware, software, and firmware. The Supplier shall provide documentation on its: • Chain-of-custody practices • Inventory management program (including the location and protection of spare parts) 28 • Information protection practices • Integrity management program for components provided by sub-suppliers • Instructions on how to request replacement parts • Maintenance commitment to ensure that for a specified time into the future, spare parts shall be made available by the Supplier The Supplier shall use trusted channels to ship critical energy delivery system hardware, such as U.S. registered mail.
NISTIR 7622 - Notional Supply Chain Risk Management Practices for Federal Information Systems	Purpose: to provide federal departments and agencies with a notional set of repeatable and commercially reasonable supply chain assurance methods and practices that offer a means to obtain an understanding of, and visibility throughout, the supply chain.	Section 4.3: Establish and Maintain the Provenance of Elements, Processes, Tools, and Data “Provenance can be achieved through both physical and logical techniques, such as Configuration Management (CM) for tracking changes to the elements and documenting the individuals who approved and executed these changes; robust identity management and access control to establish and record authorized or unauthorized activities or behaviors; and identification/tagging of elements, processes, roles, organizations, data, and tools.”
NIST SP 800-161	Supply Chain Risk Management Practices for Federal Information Systems and Organizations	Acquirers and their system integrators should maintain the provenance of systems and components under their control to understand where the systems and components originated, their change history while under government control,

Standard Name/Reference	Description/Topic	Notable Content
		and who might have had an opportunity to change them. Provenance allows for changes from the baselines of systems and components to be reported to specific stakeholders. Creating and maintaining provenance within the ICT supply chain helps government agencies to achieve greater traceability in case of an adverse event and is critical for understanding and mitigating risks.
IEC 62443-4-1 Secure Product Development Life-Cycle Requirements	It defines a secure development life-cycle (SDL) for the purpose of developing and maintaining secure products. This life-cycle includes security requirements definition, secure design, secure implementation (including coding guidelines), verification and validation, defect management, patch management and product end-of-life.	Section 6.3.1: A process shall be employed to ensure that all products shall have a threat model specific to the current development scope of the product The implementation processes shall incorporate security coding standards that are periodically reviewed and updated and include at a minimum: a) avoidance of potentially exploitable implementation constructs – implementation design patterns that are known to have security weaknesses; b) avoidance of banned functions and coding constructs/design patterns – software functions and design patterns that should not be used because they have known security weaknesses; c) automated tool use and settings (for example, for static analysis tools); d) secure coding practices; e) validation of all inputs that cross trust boundary. f) error handling

Standard Name/Reference	Description/Topic	Notable Content
ISO/IEC SO/IEC 27036-1 – Information Security in Supplier Relationships	Provides an overview of the guidance intended to assist organizations in securing their information and information systems within the context of supplier relationships.	Provides cloud service customers and cloud service providers with guidance on a) gaining visibility into the information security risks associated with the use of cloud services and managing those risks effectively, and b) responding to risks specific to the acquisition or provision of cloud services that can have an information security impact on organizations using these services.
NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition	SA-12 – Supply Chain Protection SA-3 - System Development Life Cycle SA-22 Unsupported System Components	Section SA-12 (15): The organization establishes a process to address weaknesses or deficiencies in supply chain elements identified during independent or organizational assessments of such elements. Section SA-22 UNSUPPORTED SYSTEM COMPONENTS Control: The organization: a. Replaces information system components when support for the components is no longer available from the developer, vendor, or manufacturer; and b. Provides justification and documents approval for the continued use of unsupported system components required to satisfy mission/business needs.
UTC Supply Chain Risk Management for Utilities	A roadmap tailored to the utility space on how to successfully organize supplier management activities while addressing associated security risks. It is based on practical experience, numerous discussions with utilities and vendors, and recently published	Concluding supplier relationships Pg 13: “utilities need to be very conscious of organizing supplier relationship termination processes that minimize security risks after the

Standard Name/Reference	Description/Topic	Notable Content
	standards and best practice documents	relationship is completed. Specifically, utilities should ensure that the ending of a relationship with a supplier that involves a transition between different suppliers or from a supplier to the utility involves an organized transition plan where the current supplier's responsibilities and activities are assumed by the receiving party"
APPA Managing Supply Chain Risk-Best Practices for Small Entities	Summary of the best practices that are currently in use by one or more of their small members that have only low-impact BES Cyber Systems.	Best Practice B5: Third-party accreditation and vendor self-certification would improve the ability of all entities, particularly small registered entities, to select reliable vendors.
DOE C2M2	C2M2 is a public-private partnership effort that was established as a result of the Administration's efforts to improve electricity subsector cybersecurity capabilities, and to understand the cybersecurity posture of the grid. The C2M2 helps organizations—regardless of size, type, or industry—evaluate, prioritize, and improve their own cybersecurity capabilities. Supply Chain and External Dependencies Management	Pg:. 39: The Supply Chain and External Dependencies Management (EDM) domain comprises three objectives: 1. Identify Dependencies 2. Manage Dependency Risk 3. Management Activities Of note: the C2M2 focuses on identifying dependencies where suppliers provide a critical function to operations.
US Nuclear Regulatory Commission Appendix B Part 50	Control of Purchased Material, Equipment, and Services Measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors, conform to the procurement documents.	Policy for handling supplied products or services that do not adhere to procurement processes: XV. Nonconforming Materials, Parts, or Components Measures shall be established to control materials, parts, or components which do not conform to requirements in order to prevent their inadvertent use or installation. These measures shall include, as appropriate, procedures for

Standard Name/Reference	Description/Topic	Notable Content
		identification, documentation, segregation, disposition, and notification to affected organizations. Nonconforming items shall be reviewed and accepted, rejected, repaired or reworked in accordance with documented procedures.

B
EXAMPLE VENDOR PRACTICES

Cisco

https://www.cisco.com/c/en/us/about/trust-center/gdpr.html#~tab-ourcommitment

https://www.cisco.com/c/dam/en_us/about/doing_business/trust-center/docs/building-trustworthy-systems-with-CSDL.pdf?dtid=osscdc000283

Microsoft

https://www.microsoft.com/en-us/procurement/supplier-contracting.aspx

OSI

http://www.osii.com/solutions/technology/architecture.asp

ABB

https://www.nerc.com/pa/comp/Supply%20Chain%20Webinars%20DL/Supply%20Chain%20Webinar.pdf

https://new.abb.com/about/supplying/cyber-security

https://new.abb.com/about/technology/cyber-security

GE

http://www.gesustainability.com/building-things-that-matter/supply-chain/

http://www.gesustainability.com/how-ge-works/integrity-compliance/privacy-cyber-security/

Siemens

https://www.siemens.com/global/en/home/company/about/corporate-functions/supply-chain-management/collaborating-with-siemens/supplier-management.html

SEL

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C
MARKET DATA ABBREVIATIONS

BCS	Bulk Electric System Cyber System
BES	Bulk Electric System
CIP	Critical Infrastructure Protection
COTS	Commercial off-the-shelf
C2M2	Cybersecurity Capability Maturity Model
DMS	Distribution Management System
ESP	Electronic Security Perimeter
EMS	Energy Management System
EACMS	Electronic Access Control or Monitoring Systems
FERC	Federal Energy Regulatory Commission
HMI	Human Machine Interface
ICS	Industrial Control System
IDS	Intrusion Detection System
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IP	Internet Protocol
IPS	Intrusion Prevention System
IT	Information technology
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report
NRC	Nuclear Regulatory Commission
NERC	North American Electric Reliability Corporation
OT	Operations technology
O-TTPS	Open Trusted Technology Provider™ Standard

PACS	Physical Access Control System
RTAC	Real-Time Automation Controller
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCRM	Supply Chain Risk Management
VM	Virtual Machine

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-__-000**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, MIDWEST RELIABILITY ORGANIZATION, AND RELIABILITYFIRST CORPORATION FOR APPROVAL OF REGISTRATION TRANSFER REQUEST OF WISCONSIN PUBLIC SERVICE CORPORATION AND UPPER MICHIGAN ENERGY RESOURCES

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IV. CONCLUSION 8

Attachment 1 Revised Exhibit A to the Regional Delegation Agreements between the North American Electric Reliability Corporation and Midwest Reliability Organization

Attachment 2 Revised Exhibit A to the Regional Delegation Agreements between the North American Electric Reliability Corporation and ReliabilityFirst Corporation

UNITED STATES OF AMERICA
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FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-__-000**

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I. INTRODUCTION

On December 14, 2017, Wisconsin Public Service Corporation ("WPSC") and Upper Michigan Energy Resources Corporation ("UMERC") submitted requests to Midwest Reliability Organization ("MRO") and ReliabilityFirst Corporation ("RF") to transfer their North American Electric Reliability Corporation ("NERC") registration from MRO to RF. As the Electric Reliability Organization ("ERO") for North America, the North American Electric Reliability Corporation ("NERC") is responsible for establishing and maintaining the NERC Compliance Registry ("NCR") of Bulk Power System owners, operators and users that are subject to approved Reliability Standards. NERC supports the proposed transfer of WPSC/UMERC as promoting the effective and efficient administration of the Bulk-Power System ("BPS").

Requests to transfer registrations are governed by Section 1208 of the NERC Rules of Procedure ("ROP"). Consistent with Section 1208.2 of the NERC ROP, MRO and RF each posted the transfer request on its website for a 21-day comment period. MRO received one comment from Glencoe Light and Power Commission ("GLP") which concluded that "GLP has no objection nor condones the transfer." RF received one comment supporting the transfer request from Michael Dougherty, Electric Superintendent of the Cuyahoga Falls Electric Department. Per

Section 1208.2 of the NERC ROP, on April 24, 2018, MRO notified WPSC and UMERC that MRO would not oppose the request and would support NERC's determination. RF found that the requested transfer is appropriate and subsequently submitted a written request to NERC on May 1, 2018. On May 2, 2018, NERC posted information concerning the proposed transfer on its website for 21 days and received one comment in support of the registration transfer request from Cayuhoga Falls Electric Department.

On August 16, 2018, the NERC Board of Trustees approved the proposed transfer and related Regional Delegation Agreement ("RDA") amendments. NERC hereby requests that the Federal Energy Regulatory Commission ("FERC" or the "Commission") approve the following, in accordance with Section 215(e)(4) of the Federal Power Act,[1] Section 39.8[2] of the Commission's regulations and Section 1208.3 of the NERC ROP:

(1) the proposed transfers of WPSC / UMERC from the MRO footprint to the RF footprint;

(2) an effective date of January 1, 2019 for the registration transfer to RF; and

(3) revised Exhibit A to the RDAs between NERC and MRO (**Attachment 1**) and between NERC and RF (**Attachment 2**) to reflect the proposed illustrative geographic footprints of MRO and RF resulting from the transfer of WPSC / UMERC from MRO to RF.

II. NOTICES AND COMMUNICATIONS

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

[1] 16 U.S.C. § 824o (2018).

[2] 18 C.F.R. § 39.8 (2018).

[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.

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III. RATIONALE AND PROCESS FOR TRANSFER OF WPSC AND UMERC FROM MRO TO RF

Through its guidance on transfers of registered entities within the ERO Enterprise, the Commission has noted that a Regional Entity's boundary change "should be carefully considered and should serve to improve the effectiveness or efficiency of the Regional Entities' and NERC's administration of reliability, and should not merely benefit an individual registered entity."[4] The Commission noted that NERC may consider whether a transfer will improve the registered entity's contribution to BPS reliability.[5] The Commission also noted that the financial impacts of a transfer are not the determinative factor in a transfer decision.[6] NERC is responsible for promoting consistent treatment of registered entities between the Regional Entities.[7] This emphasis on consistency is intended to prevent registered entities from shopping for a favorable Regional Entity

[4] *Order Conditionally Approving Revised Pro Forma Delegation Agreement, Revised Delegation Agreements with Regional Entities, Amendments to Rules of Procedure and Certain Regional Entity Bylaws*, 133 FERC ¶ 61,061 (2010) at P 72 ("October 2010 Order"). See also *Order Denying Rehearing*, 134 FERC ¶ 61,179 (2011) at P 15 ("March 2011 Order").

[5] March 2011 Order at P 10.

[6] March 2011 Order at P 8.

[7] October 2010 Order at P 73.

because the authority delegated to the Regional Entities will be applied in the same way among the Regional Entities.[8]

The process and criteria to apply for requests to transfer registration from one Regional Entity to a different Regional Entity is governed by Section 1208 of the NERC ROP and is consistent with the Commission's guidance. The Section 1208 requirements are publicly posted on NERC's website as part of the NERC ROP and they call for the evaluation of the following factors:

(1) the location of the registered entity's BPS facilities in relation to the geographic and electrical boundaries of the transferee Regional Entity;

(2) the impact of the proposed transfer on other BPS owners, operators, and users, including affected Reliability Coordinators ("RCs"), Balancing Authorities ("BAs"), and Transmission Operators ("TOPs"), as appropriate;

(3) the impact of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load Serving Entities of the transferee Regional Entity;

(4) the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the registered entity being transferred;

(5) the registered entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the registered entity would be transitioned from its current Regional Entity to the transferee Regional Entity; and,

(6) any other reasons NERC and the transferee Regional Entity consider relevant.

a. WPSC/UMERC's Facilities Have More Geographic and Electrical Boundaries with RF than with MRO.

The analysis began by examining the geography of WPSC / UMERC facilities. WPSC serves approximately 444,000 electric customers, and is located in eastern Wisconsin along Lake

[8] October 2010 Order at P 73.

Michigan. WPSC shares its northern and southern boundaries and a portion of its western boundary with RF and the remaining portion of its western boundary with MRO. WPSC's eastern boundary is with Lake Michigan, with the remainder of RF's footprint to the north, south, and east of Lake Michigan. WPSC's neighbor to the north, south and west is Wisconsin Electric Power Company ("Wisconsin Electric"), (depicted on the map as WEC and MIUP), which is located in RF. In June 2015, Wisconsin Electric's parent company, WEC Energy Group, acquired WPSC. Following this acquisition, WPSC relocated its Balancing Authority Control Center and Backup Control Center to the RF region, where they are now co-located with Wisconsin Electric's Control Centers.

In 2017, WEC Energy Group established UMERC, a new company consisting of Wisconsin Electric's distribution assets in the Upper Peninsula of Michigan (located in RF) and WPSC's distribution assets in the Upper Peninsula of Michigan (located in MRO). Consequently, UMERC is now a cross-regional company with the majority of its customers (75%) and distribution lines (80%) in RF. UMERC has a total peak load of 110.9 MW. Transferring the registration of WPSC and UMERC-MRO territory to a single Regional Entity would make one contiguous region out of these several geographic islands.

Registered entity alignment within a contiguous and interconnected regional boundary is a critical component of reliability because of the resulting planning and operational synergies. Placing transmission paths within a common Regional Entity boundary would enhance regional planning coordination and promote efficient and reliable system operations between registered entities. WPSC / UMERC have more significant electrical connections with RF than MRO. UMERC has 75% of its customers and 80% of its distribution lines in RF. Similarly, WPSC has more Bulk Electric System ("BES") tie lines with RF than MRO as well as a greater number of high-voltage BES tie lines to RF than MRO. WPSC has 23 tie lines with RF, while it has 14 with

MRO. Out of WPSC's 23 tie lines with RF, five are 345 kV, seventeen are 138 kV, and one is 115 kV. Out of WPSC's 14 tie lines with MRO, three are 345 kV, one is 161 kV, four are 138 kV, and the remaining six are 115 kV. Finally, more than 60% of the high voltage electrical interconnections with the WPSC BA are within the RF region. UMERC-MRO has only one 138 kV interconnection with UMERC-RF and one 138 kV interconnection to WPSC. UMERC-MRO has no other interconnections above 100 kV. Therefore, NERC supports maintaining the UMERC-MRO ties with the larger percentages of other high voltage electrical interconnections of the WPS BA in RF.

As a result of the significance of these geographic, operational, and electric connections with RF, NERC believes it is in the best interest of the effective and efficient administration of BPS reliability to grant WPSC/UMERC's transfer request.

b. The Registration Transfer of WPSC/UMERC's Facilities Will Have a Negligible Impact on other BPS owners, operators, and users.

NERC has emphasized maintaining relationships within a common Regional Entity footprint to promote the efficient and effective administration of reliability. In all instances, NERC has considered the Reliability Coordinator, Balancing Authority, Transmission Operator, and Planning Authority / Planning Coordinator alignment, as well as the physical location of the underlying facilities of the Transmission Owners, Generator Owners, Generator Operators, Transmission Planners and Distribution Providers.

The interactions between reliability functions is important to understanding the reliable operation of the BES. WPSC is registered as a local Balancing Authority (pursuant to a coordinated functional registration with MISO), Distribution Provider, Generation Owner, Generation Operator and Resource Planner. UMERC is registered as a Distribution Provider.

Moving WPSC / UMERC's registration from MRO to RF will not affect MISO serving as their Balancing Authority and Reliability Coordinator as MISO is registered in both MRO and RF. Furthermore, no changes are being proposed for the WPSC local Balancing Authority boundaries. American Transmission Company and Dairyland Power Cooperative will remain as the Transmission Operators for those WPSC assets for which they currently service that function. As a result, there will be no change or impact on other BPS owners, operators and users.

c. RF's Staffing, Resources, Budgets and Assessments Resources to Perform CMEP Activities for WPSC/UMERC Are Not Affected as RF Serves as Lead Regional Entity for WPSC/UMERC's CMEP Activities.

Following the acquisition of WPSC and the creation of UMERC, WEC Energy Group established a single, uniform compliance program for Wisconsin Electric and WPSC/UMERC. RF and MRO agreed that RF would serve as its Lead Regional Entity for all Compliance Monitoring and Enforcement Program ("CMEP") activity pursuant to the Coordinated Oversight Program. This arrangement is memorialized under agreements between MRO and RF. As a result of the existing CMEP arrangement, RF will not need additional resources to perform CMEP activities for WPSC/UMERC if the Commission approves the transfer of their registration from MRO to RF. Furthermore, no transfer of CMEP materials is required. The registration transfer of WPSC/UMERC to RF will allow RF to maintain regulatory oversight for WPSC/UMERC. As such, RF has an existing understanding of WPSC/UMERC and their operations, risk profiles, compliance history and challenges. RF regularly interacts with WPSC/UMERC during audits and spot checks, collaboratively works with WPSC/UMERC during any enforcement actions that may arise. Finally, RF already provides WPSC/UMERC with training and outreach activities such as workshops and assist visits.

III. AMENDMENTS TO THE MRO AND RF REGIONAL DELEGATION AGREEMENTS WITH NERC

Upon FERC approval of this Petition, the parties propose to amend the Regional Delegation Agreements between NERC and MRO, and NERC and RF, respectively, to reflect the new regional boundaries resulting from the reassignment of entities discussed above. The term of the revised Regional Delegation Agreements will not change. Revised maps in Exhibit A to each Regional Delegation Agreement are attached as **Attachment 1** and **Attachment 2**. The revised maps were approved by the MRO and RF Boards on August 30, 2018.

IV. CONCLUSION

For the reasons set forth above, the Petitioners respectfully request that the Commission approve the (1) the proposed transfers of WPSC/UMERC registered entities from MRO to RF, and (2) the proposed amendments to Exhibit A to the NERC-MRO and NERC-RF RDAs to reflect the corresponding regional boundary changes.

Respectfully submitted,

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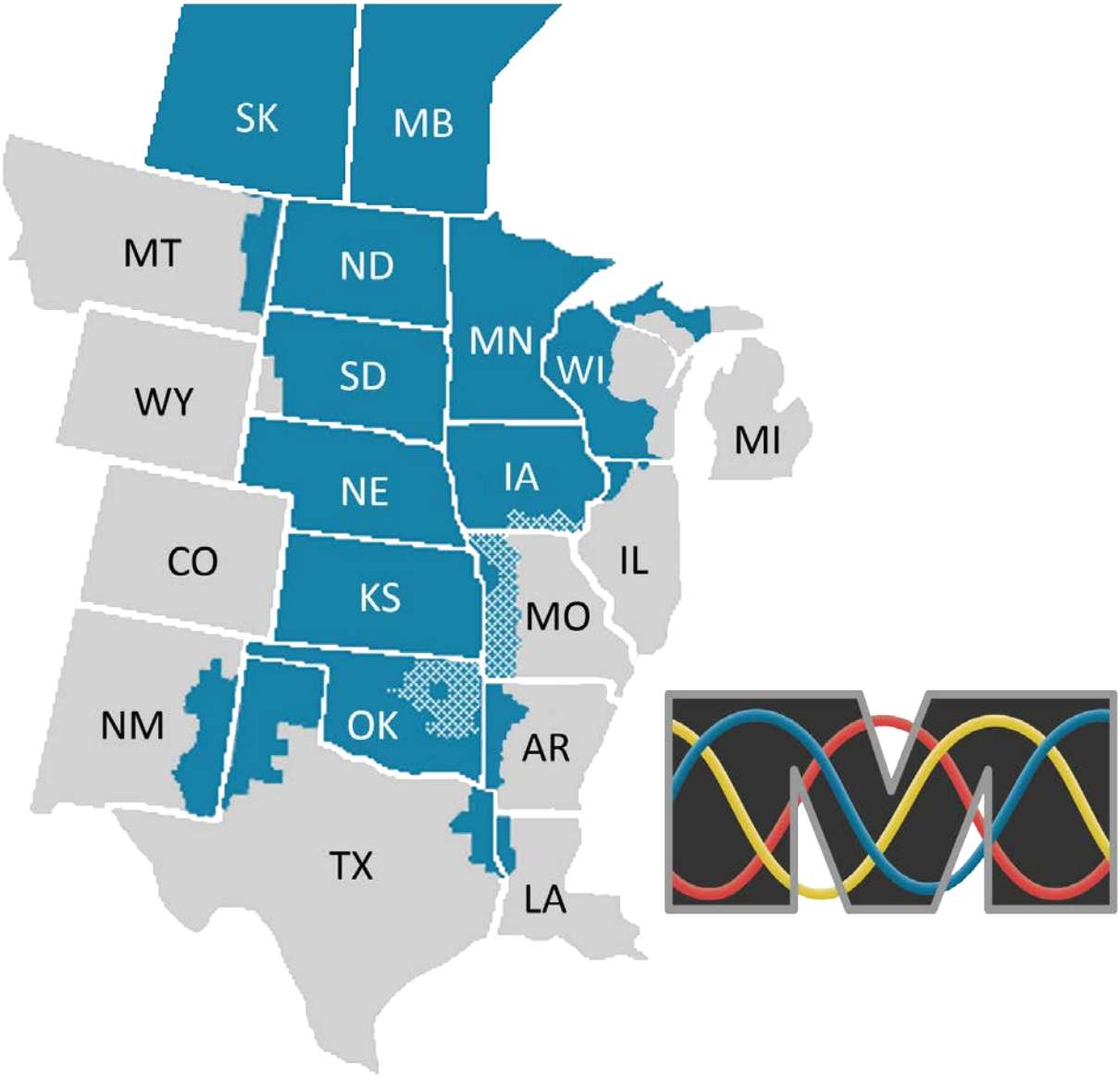
Date: September 26, 2018

Attachment 1

Revised Exhibit A to the Regional Delegation Agreements between the North American Electric Reliability Corporation and Midwest Reliability Organization

Exhibit A — Regional Boundaries

MRO is one of seven Regional Entities that operates under a Delegation Agreement with the North American Electric Reliability Corporation (NERC). MRO is a not for profit entity committed to safeguarding and improving the reliability of the Bulk Power System in all or part of the states of Arkansas, Illinois, Iowa, Kansas, Louisiana, Michigan, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin as indicated in the map below and provided in the NERC Compliance Registry and the Canadian provinces of Manitoba and Saskatchewan.



Attachment 2

Revised Exhibit A to the Regional Delegation Agreements between the North American Electric Reliability Corporation and ReliabilityFirst Corporation

Exhibit A — Regional Boundaries

The Boundaries of ReliabilityFirst Corporation (ReliabilityFirst) are defined by the service territories of Load Serving Entities (LSEs) and include all of New Jersey, Delaware, Pennsylvania, Maryland, District of Columbia, West Virginia, Ohio, Indiana, Lower Michigan and portions of Upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia as shown on the map below. In addition, transmission systems and generation within the metered boundaries of the LSEs are within ReliabilityFirst even if outside the respective service territories shown. The area is electrically contiguous.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 18, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Western Electricity Coordinating Council Bylaws
Docket No. RR_-_000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits for approval the "*Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Western Electricity Coordinating Council Bylaws*." Through the proposed amendments, the Western Electricity Coordinating Council ("WECC") seeks to: (1) bring the WECC mission into harmony with the mission of the Electric Reliability Organization; (2) remove and/or revise obsolete and outdated definitions; (3) update voting and notice requirements to reflect the use of technology; (4) codify the WECC practice of providing member representation on the Nominating Committee; (5) clarify the process for filling vacant director positions; (6) streamline committee governance language by removing committee descriptions and governance requirements from the WECC Bylaws as they are covered by WECC-Board approved committee charters; (7) remove standards development procedures from the WECC Bylaws; and (8) remove obsolete language related to WECC's 2014 transition to an independent organization.

This filing consists of: (1) this transmittal letter; (2) the narrative text of the Petition that follows this transmittal letter; and (3) Attachments 1 and 2 to the Petition that contain clean and

redline versions of the proposed amendments to the WECC Bylaws, respectively. All documents are being transmitted in a single PDF file.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR_-_000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO THE WESTERN ELECTRICITY COORDINATING COUNCIL BYLAWS

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September 18, 2018

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ATTACHMENT 1: Amended Western Electricity Coordinating Council Bylaws– Clean

ATTACHMENT 2: Amended Western Electricity Coordinating Council Bylaws – Redline

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR_-_000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO THE WESTERN ELECTRICITY COORDINATING COUNCIL BYLAWS

Pursuant to Section 215(e)(4) of the Federal Power Act ("FPA")[1] and 18 C.F.R. §§ 39.1, 39.1 (2018), the North American Electric Reliability Corporation ("NERC") requests the Federal Energy Regulatory Commission's ("Commission") approval of the proposed amendments to the Western Electricity Coordinating Council's ("WECC") Bylaws.[2] These revisions are the result of WECC's multi-year review and modernization of its Bylaws, and were approved by the WECC Board of Trustees and, whenever necessary, Members in four stages.[3] As described in greater detail in Section II of this Petition, WECC proposes to amend the following sections of its Bylaws:

- revised Section 1 ("Vision and Mission");
- deleted Section 2 ("Furtherance of WECC's Mission");
- revised Section 3 ("Definitions");
- revised Section 4 ("Members and Membership");

[1] 16 U.S.C. § 824o (2018).
[2] Pursuant to the Commission's November 2, 2015 and March 23, 2016 orders in Docket No. RR15-12, Regional Entity bylaws and standard development procedures are no longer maintained as exhibits to the Regional Delegation Agreements. NERC maintains an up-to-date copy of each Regional Entity's bylaws and standard development procedure on its website at: http://www.nerc.com/AboutNERC/Pages/Regional-Entity-Delegation-Agreements.aspx.
[3] Non-substantive, administrative changes that clarify existing Bylaws requiring only WECC Board approval were approved on March 8, 2017. Non-substantive administrative changes that clarify existing Bylaws requiring WECC Board and Member approval were approved on September 12, 2017. Substantive changes requiring only WECC Board approval were approved on December 6, 2017. Substantive changes requiring WECC Board and Member approval were approved on June 19, 2018.

- revised Section 5 (“Procedures for Member Decisions”);
- revised Section 6 (“Governance”);
- revised Section 7 (“Procedures for Board Decisions”);
- revised Section 8 (“Committees”);
- revised Section 9 (“The Chief Executive Officer, Officers, and Employees”);
- revised Section 12 (“Amendments to these Bylaws”);
- removed Section 17 (“WECC Transition”); and
- removed Appendix C (“Dispute Resolution”).

Furthermore, WECC also made several administrative/ministerial changes within the Sections noted above as well as others; however these are not addressed in detail herein.

NERC staff has determined that there are no reliability-related issues raised by the proposed amendments. As amended, the WECC Bylaws continue to satisfy the five governance criteria specified in Exhibit B to the Amended and Restated Delegation Agreement between WECC and NERC. Accordingly, the NERC Board of Trustees approved the proposed amendments to the WECC Bylaws at its August 16, 2018 meeting.

Attachments 1 and **2** to this petition are clean and redlined versions, respectively, of the revised WECC Bylaws.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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II. PROPOSED AMENDMENTS TO THE WECC BYLAWS

WECC proposes to make several changes to its Bylaws, including several administrative/ministerial changes. In this Petition, NERC only discusses the substantive changes in detail.

A. Revised Section 1.0 "Vision and Mission;" Deleted Section 2.0 "Furtherance of WECC's Mission"

WECC proposes to revise its vision statement to provide that it seeks to achieve a "reliable and secure Bulk Power System ("BPS") in the Western Interconnection" and remove references to the Bulk Electric System ("BES") achieving its vision "at least cost." WECC streamlines its mission statement to state that WECC shall "effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection BPS while carrying out the responsibilities of the Regional Entity." This aligns with the vision and mission statement for the Electric Reliability Organization ("ERO"). WECC removes details of its activities in furtherance of its mission because they are more appropriately addressed in WECC's Regional Delegation Agreement and business plan and budget. Moreover, the language removed was legacy language from when WECC functioned as a regional transmission association.

B. Revised Section 3 – Definitions

WECC also proposes to add and/or update definitions in this Section consistent with other proposed revisions:

a. Sections 3.2 – "Alternate Member Representatives," 3.16 - "Member Representative," and 3.17 - "Proxy" were added and correspond with the associated changes made to Section 5.1 – "Quorum and Alternative Voting." In Section 5.1, WECC updates and aligns the procedures for Member decisions with the other changes discussed herein.

b. Section 3.14 – "Meeting" was added to correspond to the changes made to Section 5.4 – "Notice of Member Meetings" discussed herein.

C. Removed Section 4.2.6 – Subclass Organization

WECC proposes removing Section 4.2.6 from its Bylaws to allow more flexibility because most committee references and governance requirements are being moved out of the Bylaws and addressed in committee charters. The Member Advisory Committee ("MAC") subclasses were removed from the WECC bylaws because issues regarding subclasses will now be dealt with in the MAC charter.

D. Revised Sections 4.3 – Designation of Membership Class and 4.4 – Changes in Membership Class

WECC proposes revising Sections 4.3 and 4.4 to provide that all direct appeals are now made directly to the CEO rather than the Governance Committee. WECC also made capitalization changes and added clarifying language by deleting references to "Member" and replacing it with "CEO" to reflect the changes to the appeals process.

E. Revised Section 4.8 – Compliance and Enforcement

WECC proposes to remove obsolete references to the Reliability Management System and to harmonize the WECC Bylaws language with WECC's responsibilities under Section 215 of the Federal Power Act and its delegation agreement with NERC. The Reliability Management System was a pre-Section 215 set of enforceable standards applicable in the Western Interconnection.

F. Revised Section 4.9 – WECC Structure and Governance Review

WECC proposes to delete language that is no longer applicable now that the first WECC structure and governance review, post-bifurcation and post-creation of Peak Reliability, is complete. WECC clarifies the future scope of such reviews and deletes overly prescriptive language. WECC also clarifies language surrounding the obligation to obtain member approval of Board assessments and recommendations as well as to collaborate with the Member Advisory Committee and the Western Interconnection Regional Advisory Board. WECC proposes to remove limitations on the scope of this review to allow its Board and membership maximum flexibility in carrying out the review.

G. Revised Sections 5.1 – Quorum and Alternative Voting, 5.1.1 – Quorum, and 5.1.2 – Alternate Member Representative or Absentee Voting

In Section 5.1.1 WECC specifies the requirements for quorum for Director elections and deletes redundant language from a corresponding change in Section 5.1.2. In Section 5.1.2 WECC adds language to clarify the process for using an Alternate Member Representative or Proxy for voting. Furthermore, WECC deletes language regarding hard deadlines and institutes process flexibility in the hands of the Secretary.

H. Renumbered and Revised Section 5.4 – Notice of Member Meetings

WECC proposes to have the Secretary notify members of meetings in lieu of the Chief Executive Officer due to the administrative nature of this task. WECC adopts a single notice requirement for all meetings regardless of the method by which the notice is provided.

I. Revised Section 6.2 – Composition of the Board and Board Member Qualifications

WECC proposes to clarify the qualifications for becoming a Director to require that he/she must be "at the senior management or officer level." Furthermore, with respect to Board composition, WECC proposes to revise the language to specify that Director representation from British Columbia, Alberta, or Mexico warrants that the Director also have residency and certain operational experience in that jurisdiction. WECC further identifies "resolutions" as the mechanism through which the Chief Executive Officer may be appointed as a voting Board member.

J. Revised Section 6.4 – Nomination, Selection, and Compensation of Directors

WECC proposes clarifications to its nomination, selection, and compensation processes. WECC provides for non-voting representation from all member classes on the Nominating Committee and details how the Member Advisory Committee shall select non-voting members. WECC clarifies that any party may recommend candidates to the Nominating Committee; includes a new mechanism to elect Directors without a meeting; and proposes that the responsibility for a study of director compensation be given to the Board rather than the Chief Executive Officer. The Board is to direct staff to conduct the study for the Nominating Committee.

K. Revised Section 6.5 – Removal of Directors

WECC proposes to use identical language for both the election of directors (provided in Section 4.3) and the removal of directors. Specifically, instead of a majority vote for each of the

five Classes of members, WECC proposes a simple majority across at least three of the five Classes of members. WECC also specifies the mechanism through which members can initiate a vote for removal.

L. Revised Section 6.7 – Procedures for Filling Vacant Director Positions

WECC proposes to clarify the process and timelines for filling a vacancy on the Board. The Nominating Committee is required to initiate a search when there is more than one year remaining on the vacating Director's term. Vacancies may remain unfilled if less than one year remains in the term of the vacating Director, unless a temporary Director is appointed. In cases where a Director is not re-elected due to a procedural inability, WECC proposes to clarify that the Director may serve for an additional 12 months "from the original expiration date" of his or her term.

M. Revised Section 6.10 – Delegation of Board Authority

WECC proposes to clarify that Board authority can be delegated not just to any Board committee or Chief Executive Officer, but to any person, subject to the restrictions in this section, to provide the Board with flexibility. As a result, all references to "decisions by the Chief Executive Officer" are removed. For decisions delegated to a member committee, its members must be noticed.

N. Revised Section 7.4 – Board Action by Unanimous Consent

WECC proposes to specify that Board action by unanimous consent requires three business days' prior notice to members.

O. Revised Section 7.5 – Notice of Board Meetings

WECC proposes to remove the requirement for public notice via first-class mail or fax as redundant with other notice provisions are unnecessary given the prevalence of electronic communications.

P. Original Section 7.7 – Board Committees; Revised Section 8 – Member Committees

WECC proposes to remove all references to specific committees in the WECC Bylaws. Instead, WECC provides a general provision that the Board may establish committees, "related to accomplishing WECC's mission in the Western Interconnection," and that information regarding membership, responsibilities, and operations of such committees will be addressed in their respective charters instead of the WECC Bylaws. WECC also proposes, pursuant to requests from its stakeholders, to mandate a Member Advisory Committee and a Nominating Committee in its Bylaws that are currently wholly or partly populated by stakeholders. Finally, the Board standards of conduct as applied to members of Board committees are removed from the WECC Bylaws because references to board committees were removed.

Q. Revised Section 9 – The Chief Executive Officer, Officers, and Employees

WECC proposes to remove language specifying qualifications of a Chief Executive Officer to allow the Board more flexibility in identifying a qualified candidate.

R. Deleted Section 17 – WECC Transition

WECC deletes provisions that apply to the period of time when WECC transitioned from a hybrid Board to an independent Board.

S. Deleted Appendix C – Dispute Resolutions

WECC proposes to delete Appendix C because WECC's Dispute Resolution Procedure is an artifact of WECC's merger with the regional transmission associations and is no longer part of

WECC's mission. As a regulator, WECC should not arbitrate what are generally commercial disputes between its members. The WECC Board intends to create procedures for addressing disputes between members and staff.

III. WECC AND NERC APPROVALS OF THE PROPOSED AMENDMENTS

The proposed amendments can be separated into four sets of approvals for; (1) "non-substantive" changes requiring only WECC Board approval, which were approved by the WECC Board on March 8, 2017; (2) "non-substantive" changes requiring WECC Board and Member approval, which were approved by the WECC Board and Members on September 12, 2017; (3) "substantive" changes requiring only WECC Board approval, which were approved by the WECC Board on December 6, 2017; and (4) "substantive" changes requiring WECC Board and Member approval, which were approved by the WECC Board and Members on June 19, 2018. The NERC Board of Trustees approved all of the proposed amendments at its August 16, 2018 meeting.

IV. CONCLUSION

NERC respectfully requests that the Commission approves the proposed amendments to the WECC Bylaws, as shown in **Attachment 2** to this Petition.

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

Dated: September 18, 2018

ATTACHMENT 1

Amended Bylaws –to the Amended and Restated Delegation Agreement Between

North American Electric Reliability Corporation

and

Western Electricity Coordinating Council – Clean

BYLAWS

OF

THE

WESTERN ELECTRICITY COORDINATING COUNCIL

Approved by FERC [proposed date]

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APPENDICES:

A. Board Member Standards of Conduct

B. Officers and Employees Standards of Conduct

BYLAWS

of

the

WESTERN ELECTRICITY COORDINATING COUNCIL

1. Vision and Mission.

1.1 **Vision.**
A reliable and secure Bulk Power System in the Western Interconnection.

1.2 **Mission**
To effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection Bulk Power System while carrying out the responsibilities of the Regional Entity.

2.

Organizational Characteristics.

As WECC carries out activities to fulfill its mission, it will seek to develop and maintain the following characteristics:

2.1 dedication to serving the individuals, businesses, and other organizations that generate, transmit, distribute, market, use electrical energy, and regulate and develop public policy in the Western Interconnection;

2.2 efficiency in its administration, decision-making, policy and standards development, and dispute resolution processes;

2.3 the ability to maintain status as an Interconnection-wide Regional Entity and be afforded deference and delegation by ERO (or successor organization);

2.4 fair and open processes through which practices, policies, and standards are developed and implemented based on sound technical and policy analysis; and

2.5 allow access to WECC data by individuals who can demonstrate a legitimate business need for the data, provided such individuals agree to such protections and non-disclosure restrictions that may be necessary due to the nature of the data sought to be accessed and agree to pay the incremental costs of providing the data which may be requested.

3. Definitions.

The capitalized terms used in these Bylaws shall have the meanings set forth below, or if not set

forth below, shall have the meanings given them in the Glossary of Terms Used in NERC Reliability Standards.

3.1 **Affiliate.**

An Entity that directly or indirectly through one (1) or more intermediaries, controls, or is controlled by, or is under common control with, another Entity. An Entity "controls" any Entity in which it has the power to vote, directly or indirectly, 5 percent or more of the voting interests in such Entity or, in the case of a partnership, if it is a general partner. Notwithstanding the foregoing definition, for purposes of these Bylaws:

1) electric distribution cooperatives that are member-owners of a generation and transmission cooperative are not Affiliates of the generation and transmission cooperative or of each other;
2) an Entity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or U.S. federal or Canadian or Mexican national government will not be considered an Affiliate of any other entity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or federal government;
3) separate agencies of a single state or province, or of the U.S. federal or Canadian or Mexican national government will not be considered Affiliates of each other, regardless of any commonality of political control;
4) members of any joint powers authority, and such joint powers authority, will not be considered Affiliates of each other; and
5) members of a Regional Transmission Organization (RTO) will not be considered Affiliates of such RTO or of each other solely as a result of such membership.

3.2 **Alternate Member Representative.**

In the absence of the Member Representative, the Alternate Member Representative may take any action reserved for the Member Representative. All references in these Bylaws to action by the Alternate Member Representative assume the absence of the Member Representative. The Alternate Member Representative is designated in accordance with procedures approved by the Secretary.

3.3 **Annual Member Meeting.**

The annual membership meeting of WECC, as described in Section 5.2.1.

3.4 **Applicable Regulatory Authority.**

The FERC or any national, state or provincial government agency with jurisdiction to regulate or directly affect the transmission of electricity within the Western Interconnection.

3.5 **Bulk Power System.**

The term Bulk Power System shall have the definition set forth in section 215 of the Federal Power Act.

3.6 **Class.**

A grouping of Members described in Sections 4.2.1 through 4.2.5 and 4.3.

3.7 **Compliance Hearing Body**.
The hearing body that provides a balanced compliance panel to conduct hearings for the resolution of disputes concerning compliance with or enforcement of Reliability Standards that may arise between WECC (acting as Compliance Enforcement Authority for the Western Interconnection) and a Registered Entity.

3.8 **Day(s).**
Except where otherwise explicitly defined, the term "day" or "days" shall refer to calendar days.

3.9 **Delegation Agreement.**
An agreement between the ERO and WECC pursuant to Section 215 of the Federal Power Act by which the ERO delegates to WECC designated powers, rights and responsibilities regarding the reliability of the Western Interconnection.

3.10 **Electric Line of Business.**
The generation, transmission, distribution, or trading of electricity or the provision of related energy services in the Western Interconnection.

3.11 **Electric Reliability Organization (ERO).**
The organization certified by FERC under 18 C.F.R. §39.3, the purpose of which is to establish and enforce Reliability Standards for the BulkElectric System in the United States, subject to FERC review.

3.12 **Entity.**
Any individual, person, corporation, partnership, association, governmental body or organization of any kind.

3.13 **FERC.**
The Federal Energy Regulatory Commission or any successor.

3.14 **Meeting.**
A gathering in person, by telephone, or by other permitted means of the members of an officially designated WECC group (e.g., Board of Directors (Board), committee, or other group) to deliberate and take action through a vote of the group's members. Votes, decisions and actions by any WECC group can only be taken during meetings held in accordance with the requirements contained in these Bylaws or by following the requirements for written and electronic ballots as approved by the Board of Directors.

3.15 **Member.**
Any entity that has applied and been accepted for membership in WECC.

3.16 **Member Representative.**
The Member Representative, or Alternate Member Representative or designated Proxy in the absence of the Member Representative, is the only person authorized to cast the Member's ballot in elections for Director, Member Advisory Committee (MAC)

Representative, or proposed Bylaw amendments. WECC consultation with and communications to Members are performed via public postings and emails to the Member Representative and Alternate Member Representative. Only the Member Representative, or designated Alternate Member Representative, may submit comments to WECC on behalf of the Member—the Member Representative represents and speaks for the Member. Standing Committee members represent and vote on behalf of their respective members, but only on matters directly before those committees. The Member Representative is designated in accordance with procedures approved by the Secretary.

3.17 **Proxy.**
The person designated in accordance with procedures established by the Secretary to represent a Member in person at a meeting of the membership or a Member Class and to cast a ballot in person on behalf of that Member in elections for Director, MAC Representative, or proposed Bylaws amendments whenever the Member Representative and Alternate Member Representative cannot be present to cast a ballot.

3.18 **Regional Criteria**
The term Regional Criteria shall have the definition set forth in the NERC Rules of Procedure as may occasionally be amended.

3.19 **Regional Entity (RE).**
An entity having enforcement authority pursuant to 18 C.F.R. §39.8.

3.20 **Registered Entity.**
An owner, operator, or user of the Bulk Electric System or the entities registered as their delegates compliance in the North American Electric Reliability Corporation Compliance Registry or similar Entity operating in Canada or Mexico and which could be registered in the NERC Compliance Registry if it operated in the United States.

3.21 **Reliability Standard.**
A requirement approved by FERC under section 215 of the Federal Power Act, to provide for reliable operation of the Bulk Electric System in the United States. Regional Reliability Standards are specific to the Western Interconnection and shall be established using the WECC Reliability Standards Development Procedures.

3.22 **Reliability Standards Development Procedures.**
The FERC-approved process for developing and approving WECC Regional Reliability Standards (or its successor).

3.23 **Western Interconnection.**
The geographic area containing the synchronously operated electric transmission grid in the western part of North America, which includes in the United States—Arizona, California, Idaho, Nevada, Oregon, Utah, and Washington as well as parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Colorado; parts of the Canadian provinces of British Columbia and Alberta; and Baja California Norte, Mexico.

4. Members and Membership.

4.1 Voluntary Membership.

Except as otherwise may be required by applicable authority, membership in WECC is voluntary. A Member may withdraw its membership upon giving the Secretary thirty (30) days' advance written notice. However, such notice of withdrawal will not relieve the Member from fulfilling any outstanding Member obligations. Nothing herein will relieve any Member withdrawing from WECC from any obligation it may have under applicable law including, but not limited to, Section 215 of the Federal Power Act. A Member that withdraws is obligated to pay any unpaid dues owed through the remainder of the calendar year in which its withdrawal becomes effective.

4.2 Eligibility for Membership.

Subject to Section 4.5, any Entity that meets the criteria for membership in the membership classes described in Sections 4.2.1 through 4.2.5 may be a Member of WECC:

4.2.1 Class 1. Electric Line of Business Entities owning, controlling or operating more than 1000 circuit miles of transmission lines of 115kV and higher voltages within the Western Interconnection.

4.2.2 Class 2. Electric Line of Business Entities owning, controlling or operating transmission or distribution lines, but not more than 1,000 circuit miles of transmission lines of 115 kV or greater, within the Western Interconnection.

4.2.3 Class 3. Electric Line of Business Entities doing business in the Western Interconnection that do not own, control or operate transmission or distribution lines in the Western Interconnection, including power marketers, independent power producers, Load Serving Entities, any other Entities whose primary business is the provision of energy services, and those Entities that are not eligible for membership in the other Member Classes and who have a substantial interest in the purposes of WECC.

4.2.4 Class 4. End users of significant amounts of electricity in the Western Interconnection, including industrial, agricultural, commercial and retail entities as well as organizations in the Western Interconnection that represent the interests of a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public or the environment.

4.2.5 Class 5. Representatives of nations, states and provinces in the Western Interconnection, provided that such representatives will have policy or regulatory roles and do not represent national, state or provincial agencies and departments whose function involves significant direct participation in the market as end users or in Electric Line of Business activities.

4.3 **Designation of Membership Class.**

A Member of WECC may not belong to more than one Class. An applicant for membership will designate the Class for which it qualifies based on the criteria for membership set forth in Section 4.2. However, any Member owning, controlling or operating transmission facilities or distribution facilities must belong to Class 1 or 2 unless the Board grants the Member's petition for a change in Class pursuant to the provisions of Section 4.4 of these Bylaws. Applications for membership will be submitted to WECC , which will review the application to verify eligibility for membership and Class designation. An applicant whose request has been rejected or any Member that disputes the WECC's determination regarding the appropriate Member Class designation may request review by the CEO. If the applicant or any Member disagrees with the CEO's decision, the applicant or such Member may appeal this decision to the Board.

4.4 **Changes in Membership Class.**

Notwithstanding any other provision of these Bylaws, upon a petition from a Member, the WECC (subject to review by the CEO and appeal to the Board) may allow the Member to change Class if the interest of the Member is more closely aligned with the proposed Class than the Member's current Class.

4.5 **Affiliates and Distinct Business Entities.**

An Affiliate of a Member may also become a Member if the Affiliate satisfies the qualifications for membership.

4.5.1 The Affiliate applying for membership must disclose all of its Affiliates that are WECC Members and the Classes to which the Affiliates belong. Every Member will promptly notify WECC whenever it becomes, or ceases to be, an Affiliate of any other Member.

4.5.2 Affiliates may be members of the same Class; however, a group of Affiliates within a single Class may only have one vote in any WECC forum. Except as set forth in the Reliability Standards Development Procedures, a group of Affiliates within a single Class may, by providing at least three (3) business days written notice to the Secretary, split their single vote equally among all Affiliates or designate a single Affiliate as the group's voting Member.

4.5.3 For good cause shown and with the express approval of the Board, a company or organization containing functionally distinct entities within it may obtain separate memberships for such entities; provided that such entities will be considered Affiliates.

4.5.4 The Board may adopt a policy regarding whether Members may share the benefits of membership (including the right to receive information that is only available to Members) with a non-member Affiliate.

4.6 **Rights and Obligations of Membership.**

Except as otherwise provided in these Bylaws or other applicable authority, WECC Members have the following general rights and obligations:

4.6.1 The right to elect and remove Directors as described in Sections 6.4 and 6.5;

4.6.2 The right to amend these Bylaws, and to review and rescind any Board amendment of these Bylaws, in accordance with Section 12;

4.6.3 The right to receive appropriate meeting notices, as well as reports and information produced by WECC;

4.6.4 The right to attend, participate and vote in all WECC Member meetings and the right to attend Board meetings (other than closed sessions) and to comment upon all matters considered in such meetings;

4.6.5 The right to be a voting member of Committees, subject to the charters applicable to those committees, the limitations of these Bylaws and such other reasonable limitations as the Board may adopt;

4.6.6 The right to invoke the dispute resolution provisions of these Bylaws;

4.6.7 The right to petition the Board to take any action consistent with applicable law (including Section 215 of the Federal Power Act and implementing orders and regulations), these Bylaws and the articles of incorporation and to have such petition voted on in a reasonable and timely manner;

4.6.8 The obligation to abide by these Bylaws, and all decisions of WECC, subject to the exceptions set forth in Section 4.7 and the enforcement provisions of Section 4.8.

4.6.9 The obligation to designate a Member Representative and an Alternate Member Representative;

4.6.10 The obligation to pay in a timely manner the membership dues pursuant to Sections 4.1, 11.2, and, where applicable, 11.3;

4.6.11 The obligation to provide system data that the Board has determined is necessary for WECC functions and does not impose an undue burden on the Members; provided, that the Board shall adopt appropriate limitations on this obligation or procedures that protect and avoid unnecessary collection of confidential, privileged, trade secret, cybersecurity or critical energy infrastructure information or other information that the Board determines merits such protection consistent with applicable law; and

4.6.12 The obligation to support surfacing minority and majority opinions or views within their Class, along with supporting rationale to enable the Board of Directors to

make decisions based on informed judgment aligned with WECC's vision and mission, and these Bylaws.

4.7 **Limitations on Member Obligations.**

4.7.1 The obligation of Members pursuant to Section 4.6.8 will not require any Member to take any action which the Member in good faith determines would:

1) exceed the physical capabilities of the Member's electric system (or any part of another's electric system that the Member has the legal right to cause to comply with a WECC action governed by Section 4.6.8);
2) create serious and immediate risks to public health or safety (provided, that the shedding of load shall not in and of itself be deemed a serious and immediate risk to public health and safety for the purpose of this section);
3) create an immediate risk of serious damage to facilities or equipment within its electric system or cause it to operate any of its electric facilities or equipment in an unsafe manner;
4) cause the Member to violate or improperly implement an applicable law, regulation, rule, order, FERC license provision or other legal obligation; or
5) conflict with any non-power requirement applicable to the Member (including without limitation any obligation under environmental laws, regulations, court and administrative decisions or biological opinions).

4.7.2 Each Member shall retain sole control of its facilities and the use thereof, and a Member shall not be required to construct or dedicate facilities for the benefit of any other Member, or be required to take action, or refrain from action, as may be deemed necessary to maintain reliable service to its own customers and/or to fulfill its obligations to third parties; provided, that a Member shall comply with duly-adopted reliability standards applicable to its system and shall comply with any directives under existing security coordination agreements. Nothing in these Bylaws is intended to preclude application of Section 210 or 211 of the Federal Power Act.

4.7.3 The above limitations shall not be construed as altering a Member's obligation, if any, to comply with applicable Reliability Standards or enforcement orders, or any other obligation arising under 18 C.F.R. Part 39.

4.8 **Compliance and Enforcement.**

The power of WECC to enforce Member obligations other than compliance with Reliability Standards and other obligations arising under 18 C.F.R. Part 39 and applicable Canadian and Mexican regulatory requirements is limited to suspension or termination of membership as set forth in this Section; provided, that:

1) nothing in this Section will limit the power of Members to agree to additional enforcement provisions in separate contracts; and
2) nothing in this Section will limit WECC's delegated authority under Section 215 of the Federal Power Act and 18 C.F.R. Part 39 and applicable Canadian and

Mexican regulatory requirements to enforce Reliability Standards and perform other delegated or contractual functions within the Western Interconnection.

The Board may suspend or, to the extent consistent with applicable law, terminate the membership of any Member for a material failure to meet any obligation of membership set forth in these Bylaws, including, but not limited to:

1) non-payment of dues sixty (60) days after the dues become delinquent;
2) intentionally or repeatedly violating any WECC Bylaw;
3) materially breaching or intentionally violating any FERC Order or arbitration decision issued pursuant to these Bylaws;
4) willfully obstructing any lawful purpose or activity of WECC; or
5) remaining inactive as described in Section 5.7.

The Board will give the affected Member not less than twenty-one (21) days prior written notice of any proposed suspension or termination, which will include the specific basis for the proposed action and, if applicable, instructions on curing the problem. Prior to terminating a membership, the Board will consider any information provided by the Member in response to the notice described herein.

4.8.1 Suspension. The suspension of a Member will not affect the Member's rights and obligations other than that the Member will not be entitled to vote at any meeting of the Members, Classes, subclasses, or any committee until the suspension is removed, except that a suspended Member may participate in the WECC Reliability Standards Development Procedure.

4.8.2 Termination. The termination of membership will have the same effect, and be subject to the same continuing obligations, as such Member's withdrawal pursuant to Section 4.1, except that it will be effective as of the issuance date of the notice provided pursuant to Section 4.8.

4.9 **WECC Structure and Governance Review.**

At least each five (5) years, the Board of Directors, in collaboration with the Member Advisory Committee and the Western Interconnection Regional Advisory Body, will conduct a thorough assessment of whether WECC fulfill its purposes in a manner that is consistent with its mission and vision, and the provisions of Section 2.2 of these Bylaws. As part of this assessment, the Board will consider whether the standards, obligations, processes and decisions WECC imposes on its Members are timely, fair, effective, and reasonable in view of the commercial, legal, regulatory, and economic needs and objectives of the affected Members. The assessment required by this Section 4.9 will be accompanied by recommendations for any changes the Board determines are warranted by the assessment. If any recommendations require Member approval prior to implementation, the assessment and recommendations prepared by the Board in accordance with this Section 4.9 will be submitted in writing to the Members at the first Annual Meeting held after the review is completed.

5. Procedures for Member Decisions.

5.1 Quorum and Alternative Voting.

With the exception of voting on Regional Reliability Standards and Regional Criteria under the Reliability Standard Development Procedures, Members may conduct business and take votes only at duly noticed Member meetings. Members may not conduct any business of the membership as a whole at any meeting unless a quorum is first established.

5.1.1 Quorum. A majority of all Members, including a majority in at least three (3) Classes, will constitute a quorum for all meetings of the membership as a whole, including for the election of Directors. A majority of the Members of a Class or subclass will constitute a quorum for all Class or subclass meetings. Members participating through a designated Alternate Member Representative or through submission of an absentee ballot will be counted in determination of a quorum. Inactive Members, as defined in Section 5.7 of these Bylaws, will not be counted in determining a quorum at Member, Class or subclass meetings. A quorum, once established, will be deemed to continue for the balance of any Member, Class, or subclass meeting.

5.1.2 Alternate Member Representative or Absentee Voting. If a Member Representative cannot attend a meeting of the Membership or a Class meeting in person where Directors are being elected or amendments to these Bylaws are considered for approval, the Alternate Member Representative may attend and vote in place of the Member Representative. Alternatively, the Member Representative or Alternate Member Representative, may cast an absentee ballot pursuant to procedures established by the Secretary. In the absence of both the Member Representative and the Alternate Member Representative, a Member may designate a Proxy pursuant to the procedures established by the Secretary.

5.2 General Membership Meetings.

All business of the Members acting as a whole will be conducted at meetings called by advance notice to all WECC Members provided in accordance with Section 5.4. Unless stated otherwise in these Bylaws, decisions at all meetings of the Members, Classes, or subclasses will be by simple majority vote of the Members present or otherwise represented in accordance with these Bylaws, with each Member having one vote, unless other Bylaw provisions provide for the allocation of the Member's vote. The chair of the Board will preside over all general membership meetings.

5.2.1 **Annual Member Meetings.**

WECC will hold an Annual Member Meeting at a time and place determined by the Board. At the Annual Member Meeting, and at other times as provided for in these Bylaws, in addition to such other actions the Members may take, the Members and Classes will elect Directors for vacant Director positions (as provided in Section 6.4.3).

5.2.2 **Special Member Meetings.**
Members may hold special meetings whenever called by the Board. The Board will call special Member meetings whenever a majority of the Members of any Class request a special meeting or at such other times as it deems appropriate. The chair of the Board will preside over all special Member meetings.

5.3 **Member Class and Subclass Meetings**
An individual Class or subclass may hold a meeting for any purpose relevant to the interests of Class or subclass members. Such meetings will be initiated by request of one or more Class or subclass member(s), and agreement by at least fifty (50) percent of Class or subclass members.

5.4 **Notice of Member Meetings.**

5.4.1 Annual Member Meeting. The Secretary will provide at least thirty (30) days' notice to all Members and the Board of the date, place and time of the Annual Member Meeting and an agenda of the business to be conducted at such meeting.

5.4.2 Other Member Meetings. The Secretary will provide notice of regularly scheduled and special meetings to the Members not less than ten (10) days before the meeting.

5.4.3 Public Notice. Public notice of each meeting of the Members will be placed on WECC's website at least ten (10) days before such meeting.

5.5 **Open Meetings.**
All Members' meetings are open to observation by the public.

5.6 **Policymaking Authority.**
The Board of Directors may adopt policies for the interpretation and implementation of the meeting and voting procedures established in this Section 5.

5.7 **Minimum Participation Requirement**.
To be counted for quorum purposes at a meeting of the Members as a whole, Class, or subclass, a Member must actively participate at least once each calendar year either by attending a WECC meeting or voting in a WECC election. If the Member does not meet this minimum participation requirement, the Member will be considered an "inactive" Member until its active status is restored by participation as described above. An inactive Member will not be counted toward the total number of Members when establishing a quorum requirement for the Members as a whole, a Class, or a subclass. A Member may at any time designate itself an inactive Member. Such designation will be effective until the Member is reinstated to "active" status. If a Member does not participate for twenty-four (24) consecutive months, the membership will be terminated. If a membership is so terminated, reapplication for membership may be made at any subsequent time.

6. Governance.

6.1 **Board of Directors.**

Subject to those matters expressly requiring approval by the Membership, a Board of Directors elected by the Members will govern WECC. The Board will elect its own chair and vice chair from those individuals serving as Directors.

6.2 **Composition of the Board and Board Member Qualifications.**

6.2.1 The Board of Directors shall consist of nine (9) Directors. At all times, subject to temporary vacancies, the Board of Directors shall include at least three Directors who each have at least ten years of experience in the utility industry at the senior management or officer level, preferably in the Western Interconnection, including:

1) at least one Director who has transmission operations experience,
2) at least one Director who has transmission planning experience, and
3) at least one Director who has generation operations experience.

At least one Director shall possess experience in British Columbia, Alberta, or Mexico, and also be a resident of one these jurisdictions. Notwithstanding the foregoing requirements, or any Director vacancies, the Board of Directors shall at all times retain its authority and ability to govern WECC so long as a properly constituted quorum is established in accordance with section 7.1.

6.2.1.1 Transmission operations experience shall preferably include experience in control center operations.

6.2.1.2 Transmission planning experience shall preferably include experience in modeling and/or planning transmission facilities, including economic and reliability modeling.

6.2.1.3 Generation operations experience shall preferably include experience in development or operation of generation facilities, including economic and reliability modeling.

6.2.1.4 Experience in the Canadian provinces of British Columbia and/or Alberta, and/or Mexico shall preferably include, but not be limited to, those types of experience described in sections 6.2.2.1 through 6.2.2.7 below.

6.2.2 The remaining members of the Board of Directors shall be selected ensure diversity of background and experience. Desirable categories of experience include: regulatory or legal; accounting, finance or economics; environmental; end-user advocacy; information technology; compliance or standards; and public sector.

6.2.2.1 Regulatory or legal experience shall preferably include at least one of the following types of experience: state, provincial or federal industry regulation; significant litigation experience ideally at the appellate level;

evaluation of complex legal arguments; and advising clients with respect to settlements.

6.2.2.2 Accounting, finance or economic experience shall preferably include experience as a chief financial officer, a chief accounting officer, a corporate risk officer, a certified public accountant, or the equivalent thereof.

6.2.2.3 Environmental experience shall preferably include experience advocating environmental interests before local, state or federal agencies or boards, and/or leadership experience in representing environmental interests in relation to energy issues.

6.2.2.4 End-user advocacy experience shall preferably include experience advocating end-user economic interests before local, state or federal ratemaking agencies or boards.

6.2.2.5 Information technology experience shall preferably include experience as a senior level manager responsible for integrating information technology services with organizational needs in areas such as capacity planning, budget and finance, acquisition and deployment, operations, change management, application development, trade ally relationships, user support, data quality, security and similar areas.

6.2.2.6 Compliance or standards experience shall preferably include experience as a senior level officer or manager for corporate compliance with internally and/or externally imposed requirements, rules or standards.

6.2.2.7 Public sector experience shall preferably include experience representing the public interests with respect to energy issues.

6.2.3 Director Affiliation Restrictions. A Director may not be a full-time employee of a Registered Entity. Nor may a Director be affiliated with any Member or Registered Entity operating in the Western Interconnection.

6.2.3.1 For the purposes of this section, "affiliated" shall mean (1) an employee of, (2) a contractor for, (3) an employee of a contractor for, or (4) an equity owner of or a Director for a Registered Entity or Member. For purposes of determining whether a Director is "affiliated" the term "Director" shall include a spouse and/or minor child of the Director.

6.2.3.1.1 A Director with an equity interest in private or publicly traded companies that are end-users of electricity in the Western Interconnection but who is not otherwise "affiliated" pursuant to the restrictions set forth in Section 6.2.3 shall not be considered "affiliated."

6.2.3.1.2 A Director with an equity ownership in a broadly diversified mutual fund which may include interests in one of the types of organizations described in Section 6.2.3, shall not be considered affiliated provided that such equity interest cannot confer a controlling interest in a Member or Registered Entity within the Western Interconnection.

6.2.3.1.3 A Director receiving post-employment compensation, which compensation is not indexed to the success of the disbursing entity shall not be considered "affiliated."

6.2.3.1.4 A Director shall not be considered "affiliated" solely by having a contractual relationship with a state government that has one or more agencies that are Members, provided that the Director cannot be affiliated with the Member agency or agencies.

6.2.3.1.5 A Director shall not be considered "affiliated" for being a residential or small business end-user of electricity or for being affiliated with, a member of, or a contributor to an organization that represents a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public interests or the environment, but a Director shall be considered "affiliated" if the Director is an employee of, or serves as a director, trustee, or officer or in any other policy-setting capacity with respect to any such organization.

6.2.3.2 The affiliation restrictions set forth in this Section are not all encompassing. Candidates and Board members are expected to disclose all known potential financial or relationship conflicts, including any known relationships between companies they have affiliation with and/or entities described in Section 6.2.3. Furthermore, the Nominating Committee will be expected to investigate and evaluate all potential conflicts, whether financial or otherwise.

6.2.4 In addition, the Board may, by resolution, appoint the Chief Executive Officer ("CEO") of WECC to be a voting member of the Board, provided that the CEO may not be a member of a Board committee or cast either a tie-breaking vote or a vote that creates a tie. The CEO may not serve as the chair or vice chair of the Board.

6.3 **Term of Office.**

Directors will hold office for staggered terms of three (3) years, three Directors' terms ending each year. Each term shall commence, and subsequently end, on the adjournment of the Annual Member Meeting. This may result in some Director terms that are longer or shorter than exactly three years.

6.4 **Nomination, Selection and Compensation of Directors.**

6.4.1 Nominating Committee. Candidates for a Director position shall be nominated by a Nominating Committee. The Nominating Committee shall consist of seven members. Three voting members shall be Directors, designated by the Board chair, whose terms are not expiring at the next Annual Member Meeting. The remaining four voting Nominating Committee members shall be Member Advisory Committee members selected by the MAC, with two (2) members being from Classes 1, 2, and/or 3, and two (2) members being from Classes 4 and/or 5. The MAC shall also select, as non-voting members of the Nominating Committee, an international member and one member from each of the Classes that are not voting members of the Nominating Committee. Quorum for the Nominating Committee will be a majority of voting members.

6.4.1.1 If the Member Advisory Committee does not designate MAC members to serve on the Nominating Committee within 30 days of being notified of the Board chair's designation of the three Directors to serve on the Nominating Committee, the Board chair may designate MAC members to serve.

6.4.1.2 A Nominating Committee shall be formed each year not less than 180 days prior to the Annual Member Meeting. A Nominating Committee will continue to function until a replacement Nominating Committee is formed, but may not continue for a period longer than twelve (12) months from its creation, unless the Board, by resolution, authorizes a Nominating Committee to function beyond twelve (12) months.

6.4.2 Director Candidate Nominations.

6.4.2.1 The Nominating Committee shall develop candidate pools and make candidate nominations to the Members. The Nominating Committee may consider any qualified applicant in developing the candidate pool, and may identify applicants through the following process:

1) selecting and using an independent search firm to provide the Nominating Committee with a list of qualified applicants for each Director position subject to election;

2) consider an incumbent Director who is willing to stand for reelection, including a review of such Director's tenure on the Board of Directors; and

3) consider external nominations.

6.4.2.2 Any party may recommend candidates (self-recommendations and third-party recommendations) to the Nominating Committee for consideration, by submitting the following:

- the candidate's resume,
- a summary of the candidate's relevant experience,
- a disclosure statement from the candidate, and
- a letter of interest from the candidate.

All candidate recommendations must be submitted to the Nominating Committee no later than the deadline established by the Nominating Committee.

6.4.2.3 The Nominating Committee shall review the qualifications of the potential candidates and put forth one nominee for each Director position up for election.

6.4.2.4 Five (5) affirmative votes of the Nominating Committee shall be necessary to put forth a nominee for election by the Members.

6.4.2.5 At least sixty (60) days in advance of the Annual Member Meeting, the Nominating Committee chair shall forward the list of nominees to the Board chair. The Nominating Committee chair shall advise the Board chair if the Nominating Committee is unable to agree on a complete list of nominees. The Board chair may form a new Nominating Committee with different Board and MAC members who shall be tasked with nominating candidates for the remaining open Director positions.

6.4.3 Director Elections. Members will vote for each nominee separately. A candidate will be elected to the Board on receiving a majority vote of the Members as a whole in addition to a majority of the Classes (three of the five) having a majority vote from the Members of the individual Class.

Should a candidate fail to receive the required vote of the Members or Member Classes, the Board may conduct a new election for an alternate candidate put forward by the Nominating Committee, if any. Alternatively, the Board may ask the Board chair to establish a new Nominating Committee to recommence the nomination and election process. Where a candidate has not received the required vote of the Members and Classes, the Director position shall remain vacant until a candidate is elected, except as provided in Section 6.7.2

6.4.3.1 Election by Members Without a Meeting. Member elections for Directors may occur in conjunction with an Annual or Special Member Meeting as described elsewhere in these Bylaws, or voting may occur in whole or in part through submission of written or electronic ballots in accordance with procedures determined by the Secretary to ensure the integrity of the voting process.

6.4.4 Annual Compensation of Directors. Each year the Nominating Committee will make an Director compensation recommendation for the following calendar year. The Board shall direct WECC staff to initiate a Director compensation study for the Nominating Committee every other year. The latest survey so procured shall be used by the Nominating Committee in formulating its annual compensation recommendation, which shall provide an independent review of Director compensation. Any such recommendation shall require five (5) affirmative votes of Nominating Committee members. This recommendation shall be presented to the MAC no later than one hundred fifty (150) days prior to the Annual Member Meeting. The MAC shall set the compensation for the Directors at least one hundred and twenty (120) days prior to the Annual Member Meeting. When making this decision, the MAC shall consider the recommendation of the Nominating Committee and any other material relevant to setting Director compensation. If the Nominating Committee is unable to reach the five (5) vote majority necessary to make a compensation recommendation, the MAC shall make no changes to the compensation paid Directors for the following calendar year.

6.5 **Removal of Directors.**

The Members or the Board may remove a Director before completion of the Director's term of office pursuant to the following provisions.

6.5.1 Removal by the Members. Directors may be removed only for gross negligence, violation of local, state, provincial, or federal laws, gross misconduct, or failure to meet the fiduciary obligations of Directors.

6.5.1.1 Removal of a Director will be by a vote of a majority of all the Members, not just those Members voting, in addition to a majority vote from at least three of the five Classes. Removal may only take place at a meeting called for that purpose by notice provided in accordance with the notice requirements for Member meetings. A vote to consider removal of a Director will occur based on submission to the Secretary of a petition for such a vote signed by the Member Representatives of at least 20 percent of the Members in three of the five Classes.

6.5.2 Removal by the Board. The Board may remove any Director for gross negligence; violation of local, state, provincial, or federal laws; gross misconduct; or failure to meet the fiduciary obligations of Directors. Such removal will only occur upon the affirmative vote of not less than six (6) Directors.

6.6 **Resignation.**

Any Director may resign at any time by written notice to the Board delivered to the Board chair. The acceptance of a resignation will not be required to make it effective.

6.7 **Procedures for Filling Vacant Director Positions.**

6.7.1 Director Vacancies. If the position of any Director becomes vacant prior to its normal term expiration and there is more than one (1) year remaining in said term, the Nominating Committee will—within a reasonable amount of time—begin the process of choosing a successor candidate for nomination and election. The applicable requirements of this Section 6 shall apply to this nominating process, except those regarding the timing of certain actions. The Nominating Committee chair shall advise the Board chair of the Nominating Committee's nomination. If, within six (6) months of the occurrence of a vacancy, the Nominating Committee has failed to notify the Board chair of a nominee for that vacancy, the Board chair shall appoint a new Nominating Committee, with different Board and MAC members, which will commence work immediately to select a nominee for said vacancy. Alternatively, if less than one (1) year remains in the term of the vacant Director position, the position will remain vacant, unless a temporary Director is appointed as permitted by section 6.7.3, until filled in conjunction with the typical annual Director nomination and election processes described elsewhere in this Section 6.

6.7.2 Holdover to Cure Procedural Vacancies. Whenever an incumbent Director is a candidate for a Director position and is not re-elected due to a lack of quorum or other procedural deficiency, that Director may continue to serve, for no more than twelve (12) months from the original expiration date of the Director's term, until a valid election has been conducted.

6.7.3 Should the number of serving Directors fall below seven (7), the Board may appoint one or more individuals to serve as temporary Directors until replacement Directors can be elected by the Members.

6.7.3.1 In appointing temporary Directors, the Board shall select individuals whose experience ensures the Board composition requirements of Section 6.2 are satisfied.

6.8 **Duties of Directors.**

The Directors will have the following duties:

6.8.1 Fiduciary Obligation to WECC: All Directors, will have a fiduciary obligation to WECC consistent with the requirements for Directors of Utah non-profit corporations. Members of the Board will at all times act in conformance with such requirements, these Bylaws and the Standards of Conduct set forth in Appendix A.

6.8.2 Preserve Non-Affiliated Status: Throughout their terms, Directors will have a duty to avoid any affiliation that is inconsistent with the qualifications for Directors in Section 6.2.2 of these Bylaws. If a Director becomes aware of any intervening disqualification, he/she must either resign or eliminate the disqualification (e.g., dispose of securities) within sixty (60) days.

6.9 **Powers of Directors.**

The management of all the property and affairs of WECC is vested in the Board of Directors. The Board will hold annual elections to select a Board chair and vice chair and to fill any other Board officer positions that may be created by the Board or required by applicable law. The Board may exercise all the powers of WECC and do all lawful acts and things (including the adoption of such rules and regulations for the conduct of its meetings, the exercise of its powers and the management of WECC) as are consistent with these Bylaws and the Articles of Incorporation. When deliberating policy matters, the Board will give serious consideration to the recommendations of the Member Advisory Committee and the Western Interconnection Regional Advisory Body (or any successor).

6.10 **Delegation of Board Authority.**

The Board may delegate to any person or any committee any or all of its powers and authority except any power that it may not delegate pursuant to applicable Utah law, and the power to:

1) adopt any Reliability Standard;
2) approve budgets;
3) form committees;
4) amend the Bylaws;
5) elect the Board chair and other officers of the Board; and
7) hire, fire or set the terms of employment of the Chief Executive Officer.

These powers are subject to the right of any Member to appeal any of such decisions to the Board within 30 days of the committee vote on the decision by writing a letter to the Chief Executive Officer that describes in reasonable detail the grounds for appeal, and requests that the appeal be considered by the Board at its next regularly scheduled meeting, subject to applicable notice requirements. Delegation will be by resolution. Any Director may call for a vote to rescind such delegation at any time.

6.10.1 Notice to Members. Within seven (7) days of any decision delegated to a Member committee pursuant to Section 6.10, the subject Member committee must notify all Members of the decision by electronic mail, posting on the WECC website and any other means determined appropriate by the Board.

6.10.2 Board Review of Delegated Decisions. Decisions delegated pursuant to Section 6.10 will be reviewed by the Board at the request of any Director, provided such request is lodged with the Secretary within thirty (30) days of the notice. Whenever it determines that a matter requires an urgent decision, the Board may shorten the deadline for requests for review, provided that: 1) the notice and opportunity for review will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for Board review. A request for review of a decision will stay the effect of the decision pending review unless the Board in making the delegation expressly determines otherwise.

7. Procedures for Board Decisions.

7.1 **Quorum.**

No business will be conducted by the Board unless at least five (5) Directors are present, or six (6) Directors if the CEO is counted to determine a Board quorum.

7.2 **Majority Vote.**

A decision of the Board will require an affirmative vote of a majority of Directors present and not abstaining; provided that no decision of the Board shall be made with fewer than three (3) affirmative votes, or four (4) affirmative votes if the CEO is counted to determine a Board quorum. Directors may not vote by proxy or by absentee ballot, but Directors may participate in Board meetings as provided in Section 7.3 of these Bylaws.

7.3 **Attendance at Board Meetings by Teleconference.**

Any or all of WECC's Directors may participate in any meeting of the Board by telephone conference or any other means of communication that enable all Directors participating in the meeting to simultaneously hear one another. Every Director participating in a meeting in the manner described in the preceding sentence will be deemed to be present in person at that meeting.

7.4 **Board Action by Unanimous Consent.**

Unless WECC's Articles of Incorporation or applicable law provides otherwise, action required or permitted to be taken at a meeting of the Board may be taken without a meeting through one or more written consents describing the action taken. Any Board action taken by written consent must be signed by all Directors in office at the time the action is taken. Such actions require three (3) business days' prior notice to Members and Members must be given an opportunity to comment through electronic mail, comments on the website or other appropriate means. All Board actions by written consent must be filed with WECC's Board meeting minutes. Action taken under this Section is effective when the last Director signs the consent, unless the consent specifies an earlier or later effective date. Any action by written consent has the same effect as a meeting vote and may be described as such in any document.

7.5 **Notice of Board Meetings.**

7.5.1 Regular Meetings. Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at Board meetings, at least twenty-one (21) days' notice of which has been provided by the Secretary to all Directors and all Members via email and posting to the WECC website. Notice will include an agenda that will identify those matters on which a vote will be taken at the meeting. The foregoing requirement shall not preclude the Board from taking an action that is different from the specific proposed action identified in the agenda, if the relevant subject matter has been reasonably identified in the agenda. The Directors will establish a regular meeting schedule that will be made available to the Members. The schedule will include not less than two meetings of the Board annually.

7.5.2 Special Meetings. Whenever the Board chair or any three (3) Directors find that there is urgent business requiring Board action before the next regular Board meeting, a special meeting of the Board may be called. Such special meetings will be held upon as much written notice to each Director and all Members as is possible under the circumstances, but shall be no less than three (3) days. However, notice of a special meeting may be waived if: 1) the waiver is by a writing signed by a quorum of Directors; and 2) as much notice of the meeting as practicable has been given to Members via electronic mail and posted on the WECC website.

7.6 **Open Meetings.**

Except as provided in Section 7.6.1, all regular and special meetings of the Board will be open to observation by any Member and any member of the public.

7.6.1 Closed Session. Notwithstanding the provisions of Section 7.6, on an affirmative vote of two-thirds (⅔) of the Directors present, the Board may meet in closed session:

1) to consider the employment, evaluation of performance, or dismissal of an employee of WECC and to deliberate regarding decisions the Board may be called upon to make regarding the nomination, qualification, appointment, or removal of a member of the Board of Directors;

2) to discuss pending or proposed litigation or to receive other confidential attorney-client communications from legal counsel; and

3) to receive and discuss any information that is privileged, trade secret, cybersecurity, critical energy infrastructure information (as defined by the FERC), protected from public disclosure by law or that the Board determines should be confidential to protect a legitimate public interest.

7.6.1.1 Attendance by an Affected Director. Closed sessions of the Board may not be attended by a Director under the following circumstances:

1) where the qualifications or performance of the Director or the Director's spouse or children are being discussed;

2) where the Director is employed by an entity that is or is likely to become a party to the litigation being discussed; and

3) where the Director or the Board determines that the Director would have a serious and substantial conflict of interest by becoming privy to confidential attorney-client or trade secret information that is to be presented to the Board in closed session.

7.6.1.2 Announcement of Closed Session. Before adjourning into closed session, the Board chair will announce the purpose of the closed session in a manner that provides the public an understanding of the general subject matter to be discussed but which does not reveal sensitive or personal information. The Board will not discuss additional items outside the scope of this description.

7.6.1.3 Confidentiality of Closed Session. All Directors and others present will maintain the confidentiality of discussions and decisions made in closed session. The Board will appoint a secretary for each closed session to keep minutes, recording the subject matter discussed in closed session and any actions taken in closed session. After a closed session has ended, the Board chair shall provide the public a general description of the business conducted during the closed session, without breaching the confidentiality of the information used in the session.

7.7 **Waiver of Procedures.**

For any specific action at any noticed meeting of the Board, and under exigent or unusual circumstances, the Board by unanimous vote of those present may waive any procedural requirement applicable to Board decision-making, including any requirement for notice of a specific potential action, except for the following:

1) the requirement for notice of the time and place of the meeting pursuant to Section 7.5;
2) the quorum and voting requirements of Sections 7.1 and 7.2; and
3) any non-procedural limitation on the power of the Board to make a decision, including, but not limited to, those restrictions limiting the power to delegate and limiting the power to amend the Bylaws.

Whenever such action is taken, a statement describing the action, the exigent or unusual circumstances, the specific procedure waived, the basis for the waiver and the votes of all Directors present shall be posted on the website and communicated in writing or by e-mail to all Members within five (5) days.

8. Committees.

WECC will have the following committees:

8.1 **Member Advisory Committee.**

The Member Advisory Committee (MAC) shall be constituted and operated in accordance with a charter approved by the Board. In accordance with ~~said~~ its charter, the MAC shall advise the Board on any matters the Board requests the committee to evaluate or consider and advise the Board on policy, business planning, and budgetary matters as the committee deems appropriate.

8.1.1 The committee shall be comprised of three representatives from each of the five (5) Member Classes, and one representative each for British Columbia, Alberta, and Mexico.

8.1.2 Reporting to the Board. The MAC Chair, or designee, shall provide a report to the Board at each Board meeting detailing the business carried out by the MAC, and

advising the Board of MAC recommendations on matters as set forth in Section 8.1 herein. If there are dissenting MAC member opinions regarding a matter in which the MAC is advising or providing recommendations to the Board, the MAC Chair, or designee, shall present dissenting opinions and rationales in conjunction with the respective MAC advice or recommendations.

8.2 **Nominating Committee**

The Nominating Committee shall be constituted and operate as described in Section 6.4 of these Bylaws.

8.3 **Other Committees.**

The Board may establish Committees to advise and make recommendations to the Board related to accomplishing Reliability West's mission within the Western Interconnection. The membership, responsibilities, and operation of all Committees shall be described in a Board-approved charter which may contain such other details pertinent to the governance and functioning of the committee as the Board deems appropriate.

8.4 **Open Meetings.**

All committee meetings will be open, except as set forth in these Bylaws or in Board-approved policies or committee charters describing the criteria for entering into closed session applicable to the committee in question.

9. The Chief Executive Officer, Officers, and Employees.

9.1 **Designation of Officers and Terms of Office.**

WECC will have a Chief Executive Officer, a Secretary, and any other officers specified by the Board. Each officer will be appointed by the Board and will serve for the term of office specified in the Board action appointing the officer and until a successor is appointed. If an officer is also an employee of WECC, the officer's appointment will automatically end upon termination of such employment. Any two or more offices may be held by the same person except the offices of Chief Executive Officer and Secretary.

9.2 **Standards Applicable to All Employees.**

A person may not be an officer or employee of WECC if:

1) the person is also the employee of or has a contractual relationship with any Entity, or any Affiliate of any Entity, that is eligible for membership in WECC; or
2) the person has a financial interest that, in the judgment of the Board or the Chief Executive Officer, creates the fact or appearance of bias, undue influence or lack of objectivity regarding any action or decision of WECC.

The Officers and Employees Standards of Conduct attached hereto as Appendix B set forth the duty of care, duty of loyalty, duty to avoid conflicts of interest and related matters intended to promote officer and employee neutrality, objectivity and professionalism.

9.2.1 Exemptions:

9.2.1.1 Status as a residential electricity customer will not disqualify a person from employment with WECC.

9.2.1.2 A candidate for employment will not be disqualified for owning shares in a mutual fund that owns an interest in a Member or an Affiliate.

9.2.1.3 A candidate for employment will not be disqualified for receiving payments from a pension plan of a Member or an Affiliate in a form other than securities of such Member or Affiliate if the pension plan payments bear no relationship to the economic performance of the Member or Affiliate.

9.2.2 If an officer or employee comes into possession of securities in any Member or Affiliate, the officer or employee must resign or dispose of such securities within six (6) months of the date of receipt. Within six (6) months of the time a new Member is added in which an officer or employee owns securities, the officer or employee will resign or dispose of those securities.

9.3 **Employment.**
The Chief Executive Officer will be employed by the Board of Directors and will serve at the Board's pleasure. Any contract of employment with a Chief Executive Officer will permit the Board to dismiss the officer with or without cause.

9.4 **Chief Executive Officer's Duties.**
Subject to the Board's direction and delegation, the Chief Executive Officer shall have the authority necessary to plan, organize, staff, and manage WECC to achieve its mission and to perform the activities specified in Section 2 of these Bylaws. Subject to limitation by the Board, the CEO may delegate these authorities in whole or in part to other WECC employees.

9.5 **Secretary's Duties.**
In addition to any delegation from the Board, the Secretary shall have the authority and responsibilities specified in applicable Utah law pertaining to nonprofit corporations.

10. Dispute Resolution.

The Board may adopt reasonable dispute resolution procedures applicable to WECC members and staff.

11. Costs and Finances.

11.1 **Funding of Reliability Activities.**

11.1.1 U.S. Statutory Funding. WECC shall fund all activities undertaken pursuant to Section 215 of the Federal Power Act in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. The Board

shall approve a budget for such activities in time for submission to the ERO and to FERC for approval of such funding in accordance with applicable requirements.

11.1.2 International Funding. WECC shall fund reliability activities undertaken in accordance with any agreements it enters into with Canadian or Mexican Entities. Specifically:

1) Subject to (b), if a Canadian or Mexican Entity seeks membership in WECC, that Entity may elect to negotiate an agreement with WECC that provides the terms upon which that Entity will become a Member and, among other things, participate in and/or fund WECC. In such a case and unless agreed otherwise, the Canadian or Mexican Entity shall not be a Member of WECC and shall not have an obligation to fund activities undertaken by the WECC until the terms of such agreement are executed.

2) Section 11.1.2(a) shall not apply to any Canadian or Mexican Entity that is a Member as of the date of the approval of these WECC Bylaws. Existing Canadian or Mexican Members shall continue as Members in accordance with the terms and conditions of their membership as of the date of the approval of the WECC Bylaws, including the terms and conditions of any agreements in place as of the date of the approval of these WECC Bylaws. Nothing in the Section precludes existing Canadian or Mexican Members from negotiating an agreement with WECC that modifies the terms of their participation in and funding of WECC at any time.

11.1.3 Equitable Allocation of Funding. In adopting budgets for the costs of reliability activities, the Board shall endeavor to achieve an equitable allocation as between funding through Sections 11.1.1 and 11.1.2 based on the net energy to load and other relevant factors consistent with applicable law, the Delegation Agreement and any applicable agreements with Canadian or Mexican authorities.

11.2 **Dues.**

The Board may require Members to pay nominal annual dues consistent with applicable FERC requirements (or those contained in applicable agreements with Canadian or Mexican authorities) to cover reasonable costs of membership that are not funded through Sections 11.1.1 or 11.1.2. Initial dues of a Member will be submitted with a completed application for membership and will be prorated based on the Member's actual months of membership in the calendar year. In determining nominal dues, the Board may consider all relevant factors including, but not limited to, the ability of different classes of membership to pay such dues. The Board may also reduce, defer or eliminate the dues obligation of an individual Member for good cause shown.

11.3 **Funding of Non-Statutory Activities**.

To the extent that WECC elects to fund any activities not eligible for funding pursuant to Sections 11.1.1 and 11.1.2, it shall do so through the use of service fees, charges or dues applicable to the persons or entities that voluntarily participate in such activities.

Participation in or funding of such activities shall not be a condition of membership in WECC.

12. Amendments to these Bylaws.

These Bylaws may be amended by either the Board or by the Members in accordance with the following procedures.

12.1 Amendment by the Board.

Except for those provisions described below, the Board may approve an amendment of the Bylaws after providing not less than thirty (30) days' notice of the proposed amendment to all Members. Approval of such an amendment requires the affirmative votes of not less than two-thirds (⅔) of the Directors in office. Such amendment will become effective sixty (60) days after its approval by the Board unless:

1) the vote is appealed by the Members prior to the sixtieth day, or
2) subsequent regulatory approval is required.

To lodge an appeal, a majority of any Class may file a petition with the Secretary. An appeal will stay implementation of the amendment pending Member vote on the appeal. The membership will vote on whether to rescind the Board approved amendment at the next Annual Member Meeting unless the Board calls an earlier Special Member Meeting. An appeal will only be successful if a majority of all Members and a majority (three of five) of the Classes vote to rescind the amendment. If the appeal vote is not successful, then the amendment will be deemed approved as of the day of the failed Membership vote. If subsequent regulatory approval is required for the amendment, then the amendment shall be effective upon the effective date of such approval.

12.1.1 Notwithstanding the foregoing, both Board and Member approvals are required to amend provisions of these Bylaws concerning Sections 1.1 and 1.2; Section 4.2; Sections 6.2 through 6.8, inclusive; Section 7.2; Section 8; Section 10; Sections 12.1 through 12.4, inclusive; and any other sections as may be required by Utah law. In such case, the Board shall first vote on the proposed amendment. If approved by the Board, the amendment must then be noticed to Members at least sixty (60) days prior to the Annual Member Meeting or Special Member Meeting at which the Member vote will occur. The amendment will then be approved if it receives the affirmative vote of at least two thirds (⅔) of the Members who vote upon such amendment.

12.2 Amendment by the Members.

Upon a petition being filed with the Secretary by any Member or Director, at any Annual Member Meeting or Special Member Meeting the Members may amend any provision of these Bylaws; provided:

1) the proposed amendment has first been presented to the Board and not adopted;

2) Members have received not less than sixty (60) days' notice of the proposed amendment, the reasons there for and a statement of the Board's position regarding it; and

3) the amendment receives the affirmative votes of not less than two-thirds (⅔) of all Members and a majority of the Classes.

12.3 **Amendments proposed by FERC.**
FERC, upon its own motion or upon complaint, may propose an amendment to these Bylaws pursuant to 18 C.F.R. § 39.10(b).

12.4 **Remote Member Voting on Amendments Permitted.**
In all cases where a Member vote is required for approval of a proposed Bylaws amendment pursuant to section 12.1.1, that vote may occur in conjunction with an Annual or Special Member Meeting as described in section 12.1.1, or voting may occur in whole or in part through submission of written or electronic ballots in accordance with procedures determined by the Secretary to ensure the integrity of the voting process, provided that in such cases the proposed amendment has been noticed to Members at least thirty (30) days prior to the beginning of balloting.

13. Termination of Organization.

WECC may be terminated on a vote of a majority of the Members in accordance with the provisions of Utah law, the Federal Power Act the Delegation Agreement and applicable agreements with Canadian or Mexican authorities. Immediately upon such a vote, the Board will, after paying all debts of WECC, distribute any remaining assets in accordance with the requirements of Utah law, the Internal Revenue Code and these Bylaws.

14. Miscellaneous Provisions.

14.1 **Limitation on Liability.**
It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in Section 4.8 hereof shall be the sole and exclusive remedies available hereunder for any nonperformance of obligations under these Bylaws. Subject to any applicable state or federal law that may specifically limit a Member's ability to limit its liability, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members or to third parties for any loss or damage to property, loss of earnings or revenues, personal injury, or any other direct, indirect, or consequential damages or injury that may occur or result from the performance or nonperformance of these Bylaws, including any negligence, gross negligence, or willful misconduct arising hereunder. This Section 14.1 of these Bylaws applies to such liability as might arise between Members under these Bylaws. This Section 14.1 does not apply to parties to the Agreement Limiting Liability Among Western Interconnected Systems ("WIS Agreement") with respect to matters covered by the WIS Agreement and does not apply to any liability provision in any other agreement.

14.2 **Indemnification.**

WECC shall indemnify and hold harmless its Directors, officers, employees, agents and advisors against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements), resulting from or relating to, in any way, any claim, action, proceeding or investigation, instituted or threatened, arising out of or in any way relating to any action taken or omitted to have been taken (or alleged to have been taken or omitted to have been taken) by such person in connection with actions on behalf of WECC, and against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements) incurred in connection with any settlement of any such claim, action, proceeding or investigation unless such action of such person is determined to constitute fraud, gross negligence, bad faith or willful misconduct with respect to the matter or matters as to which indemnity is sought.

14.3 **No Third-Party Beneficiaries.**

Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to or any liability to any third party.

14.4 **Informal Inquiries for Information.**

Nothing in these Bylaws shall preclude:

1) a Member from making an informal inquiry for information outside of the procedures outlined in Section 4.6.11 hereof to another Member and

2) that other Member from responding voluntarily to that informal inquiry, provided, however, that any such response to an informal inquiry for information shall not be binding upon that other Member and shall be used by the Member making the informal inquiry for informational purposes only.

15. Incorporation.

WECC shall organize itself as a non-profit corporation pursuant to the laws of the state of Utah regarding non-profit corporations under the name "Western Electricity Coordinating Council." All Members agree to take no actions that would contravene the ability of WECC to maintain its status as a non-profit corporation existing pursuant to the Utah Act. The Board shall adopt these Bylaws as the Bylaws of WECC as a non-profit corporation.

WECC is intended to qualify as an organization described in Section 501(c)(4) of the Internal Revenue Code. No part of any net earnings of WECC shall inure to the benefit of any Member or individual. Upon liquidation, to the extent consistent with the Internal Revenue Code and Utah law, any monies remaining from assessments paid by Members for the costs of WECC shall be rebated to Members in proportion to their payments. Any remaining assets of WECC shall be transferred to another organization exempt from tax under Section 501(a) of the Internal Revenue Code, or government agency, promoting the same purposes as WECC, as designated by the Board.

16. Governing Law.

Unless otherwise agreed, if any conflict of law arises under these Bylaws among the Members, the laws of the United States of America shall govern, as applicable. The venue for any legal action

initiated under these Bylaws shall be the city and state (or province) in which the headquarters of WECC is located.

APPENDICES

A. Board Member Standards of Conduct

B. Officers and Employees Standards of Conduct

Appendix A
Standards of Conduct for
Members of the WECC Board of Directors

By accepting appointment to the Board of Directors (the "Board") of the Western Electricity Coordinating Council ("WECC"), a Director agrees to abide by the duties required of corporate directors and trustees. Utah law (and similar law in other states) imposes quasi-fiduciary duties of care and loyalty on all corporate directors or trustees, including directors and trustees of nonprofit corporations. For as long as the Director remains a member of the Board of Directors of WECC, the Director will abide by the following standards of conduct.

I. Duty of care. The Directors of a corporation are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation. This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

A. Each Director will regularly attend Board of Directors meetings, digest the materials sent, participate in Board discussions and make independent inquiries as needed.

B. In voting on any matter before the Board or otherwise acting in the capacity as a Director, each Director will:

1. make reasonable inquiry to be informed of the nature and consequences of the matter or action at issue;

2. exercise, at a minimum, the degree of care, skill, and diligence that an ordinarily prudent business person would exercise under similar circumstances; and

3. act in a manner, the Director believes to be in the best interests of WECC and the membership of WECC, taken as a whole.

C. In exercising the duty of care described in paragraphs IA and B above, a Director has the right to rely on statements by the persons immediately in charge of business areas of WECC, to rely on professionals and experts (such as engineers, accountants and lawyers) and to rely on committees of WECC, unless facts or circumstances appear which would prompt further concerns of the ordinarily prudent person.

II. Duty of loyalty. The duty of loyalty imposes on a Director the obligation to remain loyal to WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain. This duty does not preclude a Director from being employed in a competing or related business so long as the Director acts in good faith and does not interfere with the business of WECC.

A. Each Director will carry out the duties of a Director in good faith.

B. Each Director will refrain from using any influence, access, or information gained through service as a Director to confer any improper personal benefit (financial or otherwise) upon the Director, any family member, or any person living in the Director's household.

C. Each Director will refrain from using any influence, access, or information gained through service as a Director to confer an improper benefit (financial or otherwise) on any organization:

1. for which the Director serves as an officer, director, employee, consultant, or in any other compensated or management position; or

2. in which the Director or any family member or person living in the Director's household has a material financial interest (whether as a shareholder, partner, or otherwise).

D. To the extent permitted by law, each Director will maintain the confidentiality of:

1. any confidential or proprietary information of WECC disclosed or available to the Director;

2. any confidential or proprietary information of WECC Member(s) to which the Director has access by virtue of the status as Director; and

3. any confidential or proprietary information of third parties that has been provided to WECC or the Board on condition of confidentiality.

E. Conflicts of Interest. Because conflicts of interest may arise, specific guidelines are provided. In general, conflicts of interest involving a Director are not inherently illegal nor are they to be regarded as a reflection on the integrity of the Board or of the Director. It is the manner in which the Director and the Board deal with a disclosed conflict that determines the propriety of the transaction.

Directors of nonprofit corporations may have interests in conflict with those of the corporation. The duty of loyalty requires that a Director be conscious of the potential for such conflicts and act with candor and care in dealing with these situations.

The following are guidelines for Directors with actual or potential conflicts of interest:

1. Each Director has a responsibility to recognize potential conflicts of interest and to be guided when acting as a Director by his or her independent judgment of what is in the best interests of WECC and the membership of WECC, taken as a whole. If any Director has questions about whether a conflict of interest exists, he or she may make inquiry to the Chief Executive Officer of WECC for advice.

2. Potential conflicts of interest may arise because of a Director's private, individual interests (personal conflicts of interest) or because of relationships the Director may

have with other organizations or interest groups (organizational conflicts of interest). Current or past employment or other compensation-based relationships with one or more WECC Members are examples of potential organizational conflicts of interest. Whether a potential conflict of interest is personal or organizational, in all cases involving WECC affairs a Director's conflicting interests are subordinate to those of WECC and the membership of WECC, taken as a whole.

3. Personal conflicts of interest.

   a. Personal conflicts of interest exist if a Director, a member of the Director's family, or a person sharing the Director's household:

      1) has a material financial interest in a matter or transaction that comes before the Board for action; or

      2) stands to receive a benefit (in money, property, or services) from a transaction involving WECC to which the person is not legally entitled.

   b. In cases of personal conflicts of interest, the affected Director's obligations are to:

      1) disclose to the Board, before the Board acts with respect to that matter, the material facts concerning the Director's personal conflict of interest; and

      2) refrain from voting, and from attempting to influence the vote of any other Director(s), in those matters in which the Director has a personal conflict of interest.

4. Organizational conflicts of interest.

   a. An organization has a "direct" conflict of interest if a decision by the Board would confer material benefits on that organization that other WECC Members would not share, or impose material detriments or costs on that organization that other WECC Members would not share. The fact that many if not all Members are affected to some extent by Board decisions on core issues such as standards, new transmission lines and their ratings, does not create or constitute a "direct" conflict of interest.

   b. It is not a "direct" conflict of interest for a Director to be associated with an organization or an interest group that may stand to benefit from decisions made or actions taken by the Board, so long as the Director does not attempt to use the position of Director to confer special benefits on associated organizations or interest groups when other WECC Members would not share in those benefits.

c. In cases of potential "direct" organizational conflicts of interest, the affected Director's obligations are to:

1) disclose to the Board, before the Board acts with respect to the matter, the material facts concerning the organizational conflict of interest; and

2) refrain from voting and from attempting to influence the vote of any other Director(s) with respect to the proposed action or decision.

Appendix B
Officers and Employee
Standards of Conduct

By accepting employment with the Western Electricity Coordinating Council ("WECC"), an Employee agrees to abide by these Standards of Conduct. For the purpose of these Standards, an Employee includes each and all officers, employees and substantially full-time consultants and contractors of WECC.

I. Duty of care. The Employees of WECC are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation. This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

Employees shall not have any outside employment that limits in any way their ability to fulfill their employment responsibilities to WECC. If an Employee has any question about whether outside employment is consistent with this standard, they should consult with their supervisor.

II. Duty of loyalty. The duty of loyalty imposes on an Employee the obligation to remain loyal to the WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain. WECC expects all Employees to avoid adversely affecting the public's confidence in the integrity and reputation of WECC. Any conduct or activities of any Employee should be capable of being justified and withstanding public scrutiny.

A. Each Employee will carry out his or her duties as an Employee in good faith, with integrity and in a manner consistent with these Standards and all applicable laws governing WECC.

B. Each Employee will refrain from using, or creating the appearance of using, any influence, access, or information gained through his or her service as an Employee to confer any improper personal benefit (financial or otherwise) upon himself or herself, or Family Member.[1] Employees shall not accept gifts or entertainment that would tend to affect, or give the appearance of affecting, the performance of their duties; provided, however, that Employees may accept de minimus food or entertainment or non-cash gifts received as part of a social or special occasion in amounts not to exceed $25 per source per event.

C. Each Employee will refrain from using, or creating the appearance of using, any influence, access, funds or information gained through his or her service as an Employee to confer an improper benefit (financial or otherwise) on any organization. The obligation to avoid the appearance of impropriety shall apply in particular to any organization:

1. for which the Employee is serving or has in the past served as an officer, director, employee, consultant, or in any other compensated or management position; or

1 For purposes of these Standards, a Family Member includes a spouse, domestic partner, child of the Employee, or a relative living in the same home as the Employee.

2. in which the Employee, or Family Member has a material financial interest known to the Employee (whether as a shareholder, partner, or otherwise).

D. Employees shall not use their WECC position, WECC funds or WECC resources to support any political party, candidate or proposition except as expressly authorized by the Board.

E. To the extent permitted by law, each Employee shall maintain the confidentiality of:

1. any confidential or proprietary information of WECC disclosed or available to the Employee;

2. any confidential or proprietary information of WECC Member(s) to which the Employee has access by virtue of his or her status as Employee; and

3. any confidential or proprietary information of third parties that has been provided to WECC or the Board on condition of confidentiality.

F. Conflicts of Interest. The following conflicts of interest policy shall apply to all WECC Employees. Conflicts of interest may arise from time to time. In general, conflicts of interest involving an Employee are not inherently illegal, nor are they to be regarded as a reflection on the integrity of WECC or of the Employee. It is the manner in which the Employee and WECC deal with a disclosed conflict that determines the propriety of the transaction. The following are guidelines for Employees with actual or potential conflicts of interest:

1. In general, personal conflicts of interest exist if an Employee, or a Family Member, has a material financial interest in a matter or transaction that comes before WECC for action, or stands to receive a benefit (in money, property, or services) from a transaction involving WECC to which the person is not legally entitled. For purposes of determining whether stock constitutes a material financial interest, see Paragraph F(6) below.

2. Organizational conflicts of interest exist if an Employee, or a Family Member, has a relationship with an organization or interest group that would cause a reasonable person to believe such Employee's judgment, loyalty, or objectivity might be influenced in a way that is adverse to the interests of WECC.

3. Where there is any question about potential conflicts of interest, the Employee shall disclose to the Chief Executive Officer as soon as possible and prior to when WECC takes action with respect to that matter, the material facts concerning the Employee's personal conflict of interest, and refrain from participating in, or from attempting to influence the action of any Directors or Employee(s) of WECC regarding those matters in which the Employee has a conflict of interest.

4. No Employee may be an employee, director of, or consultant to or provide services to or be associated in any way with any WECC Member without full

disclosure to, and written consent of, the Chief Executive Officer. To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(4), the Employee shall promptly notify the Chief Executive Officer, who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

5. No Employee shall participate in any electric energy transaction other than for ordinary personal use except to the extent necessary to, and consistent with, the functions of WECC. Participation in an energy transaction includes, but is not limited to, purchasing, selling, marketing, or brokering of electricity, ancillary services, electricity transmission or electricity distribution. To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(5), the Employee shall promptly notify the Chief Executive Officer who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

6. All Employees shall promptly disclose to the CEO and the Chair of the Board any direct or indirect financial interest in excess of $5,000 (including the direct or indirect ownership of securities) held by the Employee or a Family Member living with the Employee[2] in any Electric Line of Business entity as defined in Section 3.15 of the Bylaws doing business in the Western Interconnection. Upon such disclosure, the CEO and the Chair of the Board shall determine whether such financial interest constitutes a conflict of interest, or the appearance thereof, in light of the duties of the Employee, the ability to divest such financial interest without undue hardship and the totality of the circumstances. In response to such disclosure, the CEO and the Board chair may impose such remedies as are reasonable under the circumstances and consistent with section 9.3 of the Bylaws. Such remedies may include, but are not limited to, restrictions on the Employee's duties or involvement in certain matters, transfer of the Employee to another position, broader disclosure of the financial interest, voluntary or mandatory divestiture of the interest (in whole or in part) or other remedies. Pursuant to section 9.3.2 of the Bylaws, if an Employee (not a Family Member) receives a gift or inheritance of securities of a Member of WECC, or if a new Member joins WECC in which the Employee (not a Family Member) holds securities, the Employee must resign or divest such securities within six months thereafter. For the purposes of this section, none of the following shall constitute a direct or indirect financial interest:

   a. An interest that exists through diversified mutual funds;

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2 Nothing in this section shall require an Employee to investigate the financial interests of Family Members not living with the Employee. However, to the extent known to the Employee, the financial interests of a Family Member not living with the Employee may create a potential conflict of interest (or appearance thereof) subject to Sections II(B) and/or II(F)(1) of these standards, in which case disclosure pursuant to Section II(F)(3) is appropriate.

b. An interest that exists for six months following receipt of a gift or inheritance of securities of a Market Participant or acceptance of employment with WECC, whichever is later;

c. An interest that exists through a pre-existing participation in a qualified defined benefits pension plan or health benefits plan of a Market Participant so long as the benefits under such plan do not vary with the economic performance or value of the securities of such Market Participant.

ATTACHMENT 2

Amended Bylaws –to the Amended and Restated Delegation Agreement Between

North American Electric Reliability Corporation

and

Western Electricity Coordinating Council – Redline

BYLAWS

OF

THE

WESTERN ELECTRICITY COORDINATING COUNCIL

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APPENDICES:

A. Board Member Standards of Conduct

B. Officers and Employees Standards of Conduct

~~C. WECC Dispute Resolution Procedures~~

BYLAWS

oOf

tThe

WESTERN ELECTRICITY COORDINATING COUNCIL

1. Vision and Mission.

1.1 Vision.

The Western Electricity Coordinating Council ("WECC") shall seek to achieve A reliable and secure the appropriate level of Bulk Bulk PowerElectric System in the Western Interconnectionreliability at least cost considering all costs throughout the economy.

1.2 Mission

WECC is a Utah nonprofit corporation with the mission tTo effectively foster and promote reliability and efficiently mitigate risks to the reliability and security of coordination in the Western Interconnection Bulk Power System while carrying out the responsibilities of the Regional Entity. WECC will lead the stakeholders in the Western Interconnection to achieve appropriate system reliability, be the premier source of unbiased information, and serve as the trusted thought leader for the Western Interconnection by providing, consistent with these Bylaws: 1) impartial independent review and analysis of reliability issues impacting the Western Interconnection 2) development of electric reliability standards incorporating Western Interconnection experience and knowledge; 3) consistent and fair monitoring and enforcement activities for compliance with reliability standards; 4) event analysis and lessons-learned from system events; and 5) value for its membership through cost effective and efficient services and practices through: a) being a centralized repository of reliable information relating to the planning and operation of the Bulk Electric System in the Western Interconnection, b) coordinating system planning and modeling, c) sharing of, and providing comment on adherence to, recognized industry best practices, d) facilitating resolution of market seams and coordination issues, e) secure sharing of critical reliability data, and f) providing a robust stakeholder forum.

2. Furtherance of WECC's Mission

2.

2.1 **Activities to Carry Out WECC's Mission**.

2.1.1 Compliance with the Federal Power Act. WECC will carry out responsibilities and exercise rights of a Regional Entity organized on an interconnection-wide basis pursuant to Section 215 of the Federal Power Act, including any responsibilities and rights delegated to it by the ERO pursuant to a Delegation Agreement.

2.1.2 Agreements with Canada and Mexico. WECC will carry out responsibilities and exercise rights pursuant to International Reliability Agreements with Canadian or Mexican authorities.

2.1.3 Regional Coordination. WECC will act as a coordinating entity for the entire Western Interconnection for activities of regional organizations with responsibilities for reliability and market functions.

2.1.4 Standard Setting. WECC will develop and adopt reliability, operating, and planning standards, criteria and guidelines necessary to maintain the reliable operation of the Western Interconnection's interconnected Bulk Electric System, including seeking, as appropriate, variances from standards of the ERO (or any successor organization which may be created by legislation or otherwise), as well as providing a process for regional variances.

2.1.5 Certification of Grid Operating Entities. WECC will assist in certifying Grid Operating Entities in the Western Interconnection.

2.1.6 Reliability Assessment. WECC will ensure that interconnected Bulk Electric System reliability assessments are conducted as needed. WECC will do this work in conjunction with the Regional Entities to the greatest extent possible. WECC will also facilitate coordinated reliability assessments among Regional Entities.

2.1.7 Compliance Activities. With respect to enforcement of reliability standards, WECC will:

2.1.7.1 implement the Reliability Management System in effect as of WECC's formation and as the Reliability Management System may be subsequently modified in accordance with its terms;

2.1.7.2 implement any monitoring and enforcement mechanisms delegated to it pursuant to Section 215 of the Federal Power Act and any Delegation Agreement with the ERO, or required by any International Reliability Agreement with a Canadian or Mexican authority; and

2.1.7.3 administer any other monitoring and enforcement mechanisms where WECC is designated to perform administration.

2.1.8 Coordinated Regional Planning. With respect to the coordination of regional planning activities, WECC:

2.1.8.1 will develop coordinated planning policies and procedures for the Western Interconnection, including facilitation of market-based solutions, consistent with WECC/ERO standards and FERC policy.

2.1.8.2 will review and assess Local Regional Entity planning processes to determine whether WECC planning procedures have been satisfied;

2.1.8.3 will refer planning matters back to the originating Local Regional Entity for revision or other corrective actions when the WECC Board determines that WECC planning procedures have not been satisfied; and

2.1.8.4 may perform other interconnection-wide studies as needed.

2.1.9 Coordinated Operations. With respect to coordinating reliable operating activities within the Western Interconnection, WECC will develop, coordinate and promote consistent interregional operating policies and procedures for the Western Interconnection, consistent with WECC/ERO standards and FERC policy.

2.1.10 Market Interface Issues. With respect to Market Interface issues WECC will:

2.1.10.1 facilitate development of compatible and efficient practices across the Western Interconnection; and

2.1.10.2 exercise Backstop Authority where an unresolved Market Interface issue will cause Material External Impacts by taking some or all of the following actions: 1) providing a forum for and coordinating voluntary solutions among Members; 2) recommending specific solutions for voluntary adoption by Members; and 3) if necessary, proposing solutions to an Applicable Regulatory Authority.

2.1.11 Dispute Resolution. WECC will provide a process for the timely resolution of disputes between WECC Members as set forth in Section 11.

2.2 Organizational Characteristics.

As WECC carries out activities to fulfill its mission, it will seek to develop and maintain the following characteristics:

2.2.1 2.1 dedication to serving the individuals, businesses, and other organizations that generate, transmit, distribute, market, and use electrical energy, and regulate and develop public policy in the Western Interconnection;

2.2.2 2.2 efficiency in its administration, decision-making, policy and standards development, and dispute resolution processes;

2.2.3 2.3 the ability to maintain status as an Interconnection-wide rRegional reliability eEntity and be afforded deference and delegation by ERO (or successor organization); and

2.2.4 2.4 fair and open processes through which practices, policies, and standards are developed and implemented based on sound technical and policy analysis.; and

~~2.2.5 Promote an efficient western electric market by reducing or eliminating conflict, duplication and overlap among electric organizations in the Western Interconnection.~~

~~2.2.6~~2.5 ~~A~~allow access to WECC data by individuals who can demonstrate a legitimate business need for the data, provided such individuals agree to such protections and non-disclosure restrictions ~~which~~ that may be necessary due to the nature of the data sought to be accessed and agree to pay the incremental costs of providing the data which may be requested.

3. Definitions.

The capitalized terms used in these Bylaws shall have the meanings set forth below, or if not set forth below, shall have the meanings given them in the ~~NERC~~ Glossary of Terms Used in NERC Reliability Standards.

3.1 **Affiliate.**

An Entity that directly or indirectly through one (1) or more intermediaries, controls, or is controlled by, or is under common control with, another Entity. ~~-~~An Entity "controls" any Entity in which it has the power to vote, directly or indirectly, 5 percent~~%~~ or more of the voting interests in such E~~e~~ntity or, in the case of a partnership, if it is a general partner. Notwithstanding the foregoing definition, for purposes of these Bylaws:

1) ~~1)~~ electric distribution cooperatives that are member-owners of a generation and transmission cooperative are not Affiliates of the generation and transmission cooperative or of each other;
2) ~~2)~~ an E~~e~~ntity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or U.S. federal or Canadian or Mexican national government will not be considered an Affiliate of any other entity controlled by or operating as a unit, agency, or subdivision of a local, state, provincial, or federal government;
3) ~~3)~~ separate agencies of a single state or province, or of the U.S. federal or Canadian or Mexican national government will not be considered Affiliates of each other, regardless of any commonality of political control;
4) ~~4)~~ members of any joint powers authority, and such joint powers authority, will not be considered Affiliates of each other; and
5) ~~5)~~ members of a~~n~~ Regional Transmission Organization (RTO) will not be considered Affiliates of such~~–~~ RTO or of each other solely as a result of such membership.

3.2 **Alternate Member Representative.**

In the absence of the Member Representative, the Alternate Member Representative may take any action reserved for the Member Representative. All references in these Bylaws to action by the Alternate Member Representative assume the absence of the Member Representative. The Alternate Member Representative is designated in accordance with procedures approved by the Secretary.

~~3.2~~3.3 **Annual Member Meeting.**

The annual membership meeting of WECC, as described in Section 5.2.1~~3~~.

~~3.3~~3.4 **Applicable Regulatory Authority.**
The FERC or any national, state or provincial government agency with jurisdiction to regulate or directly affect the transmission of electricity within the Western Interconnection.

3.5 **Bulk Power System.**
~~3.4~~ **The term Bulk Power System shall have the definition set forth in section 215 of the Federal Power Act.**

~~3.5 Backstop Authority.~~
~~The ability, obligation, or responsibility of WECC to address an issue when the WECC Board determines that a Local Regional Entity(ies) holding Primary Authority has not resolved an issue, has created incompatible resolutions or has not acted. In each case where these Bylaws authorize WECC to exercise Backstop Authority, the provisions that authorize Backstop Authority will also specify the conditions necessary to trigger Backstop Authority and the actions that fall within WECC's exercise of Backstop Authority.~~

~~3.6 Balancing Authority.~~
~~The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.~~

~~3.7 Ballot Body.~~
~~The Ballot Body consists of WECC members and non-members that have been determined eligible for the voting sectors described in the Reliability Standards Development Procedures and may, therefore, vote on Regional Criteria and Regional Reliability Standards.~~

~~3.8 Board of Directors (Board).~~
~~WECC Board of Directors, collectively, as described in Section 6.~~

~~3.9~~3.6 **Class.**
A grouping of Members described in Sections 4.2.1 through 4.2.5~~7~~ and 4.3.

~~3.10 Commercial Practices.~~
~~The products and practices involved in trading electricity. The term "Commercial Practices" only refers to an interaction among market entities that does not affect or require assistance from Grid Operating Entities that have grid reliability responsibilities.~~

~~3.11~~3.7 **Compliance Hearing Body**.
The hearing body ~~used for the purpose of~~that provides~~ing~~ a balanced compliance panel to conduct hearings for the resolution of disputes concerning compliance with or enforcement of Reliability Standards that may arise between WECC (acting as Compliance Enforcement Authority for the Western Interconnection) and a Registered Entity.

3.8 **Day(s).**

Except where otherwise explicitly defined, the term "day" or "days" shall refer to calendar days.

~~3.12~~3.9 **Delegation Agreement.**

An agreement between the ERO and WECC pursuant to Section 215 of the Federal Power Act by which the ERO delegates to WECC designated powers, rights and responsibilities regarding the ~~administration within~~ reliability of the Western Interconnection ~~of electric Reliability Standards adopted or approved by the ERO and the FERC~~.

~~3.13 Director.~~

~~An individual member of the WECC's Board of Directors.~~

~~3.14~~3.10 **Electric Line of Business.**

The generation, transmission, distribution, or trading of electricity or the provision of related energy services in the Western Interconnection.

~~3.15~~3.11 **Electric Reliability Organization (ERO).**

The organization certified by FERC under 18 C.F.R. §39.3, the purpose of which is to establish and enforce Reliability Standards for the Bulk ~~-~~Electric System in the United States, subject to FERC review.

~~3.16~~3.12 **Entity.**

Any individual, person, corporation, partnership, association, governmental body or organization of any kind.

~~3.17~~3.13 **FERC.**

The Federal Energy Regulatory Commission or any successor.

~~3.18 Grid Operating Entity.~~

~~Any operating entity, such as a Balancing Authority, that is certified pursuant to Section 2.1.5 of these Bylaws to be responsible for reliable operation of a portion of the Western Interconnection.~~

~~3.19 International Reliability Agreement.~~

~~An agreement between WECC and any appropriate Canadian or Mexican authority related to WECC's powers, rights and responsibilities regarding the administration of electric reliability standards applicable within such authority's geographic area of the Western Interconnection.~~

~~3.20 Local Regional Entity.~~

~~A regional transmission organization or some other formally or informally constituted regional organization or group within the Western Interconnection, including but not limited to a Balancing Authority, a group of Balancing Authorities acting in concert, or a group of Entities that own or operate Transmission Facilities acting in concert. These Local Regional Entity boundaries can be reevaluated or modified over time.~~

~~3.21 Market Interface.~~

~~Market Interface involves all interactions among market entities and Grid Operating Entities related to transmission service and physical delivery.~~

~~3.22 Material External Impacts (MEI).~~

~~Significant effects on another Local Regional Entity or market within the Western Interconnection but outside of the Local Regional Entity or market adopting a policy, standard, practice or procedure, or implementing an action.~~

3.14 **Meeting.**

A gathering in person, by telephone, or by other permitted means of the members of an officially designated WECC group (e.g., Board of Directors (Board), committee, or other group) to deliberate and take action through a vote of the group's members. Votes, decisions and actions by any WECC group can only be taken during meetings held in accordance with the requirements contained in these Bylaws or by following the requirements for written and electronic ballots as approved by the Board of Directors.

~~3.23~~3.15 **Member.**

Any entity that has applied and been accepted for membership in WECC~~ and is current in the payment of dues~~.

3.16 **Member Representative.**

The Member Representative, or Alternate Member Representative or designated Proxy in the absence of the Member Representative, is the only person authorized to cast the Member's ballot in elections for Director, Member Advisory Committee (MAC) Representative, or proposed Bylaw amendments. WECC consultation with and communications to Members are performed via public postings and emails to the Member Representative and Alternate Member Representative. Only the Member Representative, or designated Alternate Member Representative, may submit comments to WECC on behalf of the Member—the Member Representative represents and speaks for the Member. Standing Committee members represent and vote on behalf of their respective members, but only on matters directly before those committees. The Member Representative is designated in accordance with procedures approved by the Secretary.

3.17 **Proxy.**

The person designated in accordance with procedures established by the Secretary to represent a Member in person at a meeting of the membership or a Member Class and to cast a ballot in person on behalf of that Member in elections for Director, MAC Representative, or proposed Bylaws amendments whenever the Member Representative and Alternate Member Representative cannot be present to cast a ballot.

~~3.24 Participating Stakeholder.~~

~~Any person or entity that is not a WECC Member, but is an interested stakeholder and has applied and been granted, pursuant to Section 8.7.2, the participation and voting rights set forth in Section 8.7.1.~~

~~3.25 Primary Authority.~~

~~The ability, obligation, or responsibility of an entity to address an issue in the first instance.~~

~~3.26~~3.18 **Regional Criteria**

The term Regional Criteria shall have the definition set forth in the NERC Rules of Procedure as may occasionally be amended ~~from time to time~~.

~~3.27~~3.19 **Regional Entity (RE).**

An entity having enforcement authority pursuant to 18 C.F.R. §39.8.

~~3.28~~3.20 **Registered Entity.**

An owner, operator, or user of the Bulk~~-~~ Electric System or the entities registered as their delegates ~~for the purpose of~~ compliance in the North American Electric Reliability Corporation Compliance Registry or similar Entity operating in Canada or Mexico and which could be registered in the NERC Compliance Registry if it operated in the United States.

~~3.29 Reliability Management System~~

~~The contracts, separate from these Bylaws, by which Members and other parties agree to certain procedures and sanctions intended to enforce specified Reliability Practices to maintain reliable electric service throughout the Western Interconnection.~~

~~3.30~~3.21 **Reliability Standard.**

A requirement approved by FERC under section 215 of the Federal Power Act, to provide for reliable operation of the Bulk~~-~~ Electric System in the United States.~~—~~ Regional Reliability Standards are specific to the Western Interconnection and shall be established using the WECC Reliability Standards Development Procedures.

~~3.31~~3.22 **Reliability Standards Development Procedures.**

The FERC-approved process for developing and approving WECC Regional Reliability Standards (or its successor) ~~attached as Exhibit C to the Delegation Agreement between WECC and North American Electric Reliability Corporation~~.

~~3.32 Transmission Facilities.~~

~~Those facilities that are defined as "transmission facilities" by FERC for purposes of the open access requirements of Section 210 and 211 of the Federal Power Act or any facilities which would be so defined if the Member were subject to FERC jurisdiction.~~

~~3.33~~3.23 **Western Interconnection.**

The geographic area containing the synchronously operated electric transmission grid in the western part of North America, which includes in the United States~~—~~Arizona, California, Idaho, Nevada, Oregon, Utah, and Washington~~,~~ as well as parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Colorado; parts of the Canadian p~~P~~rovinces of British Columbia and Alberta; and Baja California Norte, Mexico.

4. Members and Membership.

4.1 **Voluntary Membership.**

Except as otherwise may be required by applicable authority, membership in WECC is voluntary. A Member may withdraw its membership upon giving the Secretary thirty (30) days' advance written notice. ~~Notwithstanding such notice of withdrawal, all contracts, FERC orders, unpaid Member costs, and decisions of arbitration in effect or pending as of the date of the written notice of withdrawal will be followed through to completion, pursuant to these Bylaws, by the withdrawing Member; however.~~ However, such notice of withdrawal will not relieve the Member from fulfilling any outstanding Member obligations. Nothing herein will relieve any Member withdrawing from WECC from any obligation it may have under applicable law including, but not limited to, Section 215 of the Federal Power Act. A Member that withdraws is obligated to pay any unpaid dues owed through the remainder of the ~~fiscal~~ calendar year in which its withdrawal becomes effective.

4.2 **Eligibility for Membership.**

Subject to Section 4.5, any Entity ~~that is an interested stakeholder or~~ that meets the criteria for membership in the membership classes described in Sections 4.2.1 through 4.2.5 may be a Member of WECC:

4.2.1 Class 1. Electric Line of Business Entities owning, controlling or operating more than 1000 circuit miles of transmission lines of 115 kV and higher voltages within the Western Interconnection.

4.2.2 Class 2. Electric Line of Business Entities owning, controlling or operating transmission or distribution lines, but not more than 1,000 circuit miles of transmission lines of 115 kV or greater, within the Western Interconnection.

4.2.3 Class 3. Electric Line of Business Entities doing business in the Western Interconnection that do not own, control or operate transmission or distribution lines in the Western Interconnection, including power marketers, independent power producers, L~~l~~oad S~~s~~erving E~~e~~ntities, any other Entities whose primary business is the provision of energy services, and those Entities that are not eligible for membership in the other Member Classes and who have a substantial interest in the purposes of WECC.

4.2.4 Class 4. End users of significant amounts of electricity in the Western Interconnection, including industrial, agricultural, commercial and retail entities as well as organizations in the Western Interconnection that represent the interests of a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public or the environment.

4.2.5 Class 5. Representatives of nations, states and provinces in the Western Interconnection, provided that such representatives will have policy or regulatory roles and do not represent national, state or provincial agencies and departments whose function involves significant direct participation in the market as end users or in Electric Line of Business activities.

~~4.2.6 Sub-Class Organization. A Member Class may subdivide in up to three subclasses based on a majority desire within that class for purposes of electing Member Advisory Committee representation.~~

4.3 **Designation of Membership Class.**

A Member of WECC may not belong to more than one Class. An applicant for membership will designate the Class for which it qualifies based ~~up~~on the criteria for membership set forth in Section 4.2.~~,~~ ~~H~~however, any Member owning, controlling or operating t~~T~~ransmission f~~F~~acilities or distribution facilities must belong to Class 1 or 2 unless the Board grants the Member's petition for a change in ~~Member~~ Class pursuant to the provisions of Section 4.4 of these Bylaws. Applications for membership will be submitted to WECC ~~staff~~ , which will review the application to verify eligibility for membership and ~~Member~~ Class designation. An applicant whose ~~application~~ request has been rejected or any Member ~~who~~ that disputes the WECC ~~staff~~'s determination regarding the appropriate Member Class designation may request review by the ~~Governance Committee~~CEO. If the applicant or any Member disagrees with the ~~Governance Committee~~CEO's decision, the applicant or such Member may appeal this decision to the Board.

4.4 **Changes in Membership Class.**

Notwithstanding any other provision of these Bylaws, upon a petition from a Member, the WECC ~~staff~~ (subject to review by the ~~Governance Committee~~CEO and appeal to the Board) may allow the Member to change ~~Member~~ Class if the interest of the Member is more closely aligned with the proposed Class than the Member's current Class.

4.5 **Affiliates and Distinct Business Entities.**

An Affiliate of a Member ~~that satisfies the membership qualifications~~ may also become a Member ~~provided:~~if the Affiliate satisfies the qualifications for membership.

4.5.1 The Affiliate applying for membership ~~and the Member~~ must disclose ~~to the Chief Executive Officer~~ all of its Affiliates that are WECC Members and the Classes to which the Affiliates belong. Every Member will promptly notify ~~the Chief Executive Officer~~ WECC whenever it becomes, or ceases to be, an Affiliate of any other Member.

4.5.2 Affiliates may be members of the same Class; ~~provided,~~ however, a group of Affiliates within a single Class may only have one vote in any WECC forum. Except as set forth in the Reliability Standards Development Procedures ~~Section 8.7.6~~, a group of Affiliates within a single Class may, by providing at least three (3) business days ~~advance~~ written notice to the ~~Chief Executive Officer~~ Secretary, split their single vote equally among~~st~~ all Affiliates or designate a single Affiliate as the group's voting Member.

4.5.3 For good cause shown and with the express approval of the Board, a company or organization containing functionally distinct entities within it may obtain separate

memberships for such entities; provided that such entities will be considered Affiliates.

4.5.4 The Board may adopt a policy regarding whether Members may share the benefits of membership (including the right to receive information that is only available to Members) with a non-member Affiliate.

4.6 **Rights and Obligations of Membership.**
Except as otherwise provided in these Bylaws or other applicable authority, WECC Members ~~of WECC~~ have the following general rights and obligations:

4.6.1 The right to elect and remove Directors as described in Sections 6.4 and 6.5;

4.6.2 The right to amend these Bylaws, and to review and rescind any Board amendment of these Bylaws, in accordance with Section 12;

4.6.3 The right to receive appropriate meeting notices, as well as reports and information produced by WECC;

4.6.4 The right to attend, participate and vote in all WECC Member meetings and the right to attend Board meetings (other than closed sessions ~~of Board meetings~~) and to comment upon all matters considered in such meetings;

4.6.5 The right to be a voting member of Committees, subject to the charters applicable to those committees, the limitations of these Bylaws and such other reasonable limitations as the Board may adopt~~The right to be a member of, attend meetings of, and to introduce motions, debate and to vote in the deliberations of WECC committees, subject to the limitations of these Bylaws and such other reasonable limitations as the Board may adopt from time to time~~;

4.6.6 The right to invoke the dispute resolution provisions of these Bylaws;

4.6.7 The right to petition the Board to take any action consistent with applicable law (including Section 215 of the Federal Power Act and implementing orders and regulations), these Bylaws and the articles of incorporation and to have such petition voted ~~up~~on in a reasonable and timely manner;

4.6.8 The obligation to abide by these Bylaws~~, decisions resulting from the dispute resolution process~~, and all ~~standards or~~ decisions of WECC, subject to the exceptions set forth in Section 4.7 and the enforcement provisions of Section 4.8.

4.6.9 The obligation to designate a Member Representative and an Alternate Member Representative~~notify the Chief Executive Officer promptly of changes with respect to Affiliates as provided in Section 4.5.1 of these Bylaws; and~~;

4.6.10 The obligation to pay in a timely manner the membership dues pursuant to Sections 4.1, 11.2, and, where applicable, 11.3;~~.~~

4.6.11 The obligation to provide system data that the Board has determined is necessary for WECC functions and does not impose an undue burden on the Members; provided, ~~however,~~ that the Board shall adopt appropriate limitations on this obligation or procedures that protect and avoid unnecessary collection of confidential, privileged, trade secret, cybersecurity or critical energy infrastructure information or other information that the Board determines merits such protection consistent with applicable law~~.~~; and

4.6.12 The obligation to support surfacing minority and majority opinions or views within their ~~Member~~ Class, along with supporting rationale to enable the Board of Directors to make decisions based on informed judgment aligned with WECC's vision~~,~~ and mission, and these Bylaws.

4.7 **Limitations on Member Obligations.**

4.7.1 The obligation of Members pursuant to Section 4.6.8 will not require any Member to take any action which the Member in good faith determines would:

~~a) would~~ exceed the physical capabilities of the Member's electric system (or any part of another's electric system that the Member has the legal right to cause to comply with a WECC action governed by Section 4.6.8);

1)

2) ~~b) would~~ create serious and immediate risks to public health or safety (provided, ~~however,~~ that the shedding of load shall not in and of itself be deemed a serious and immediate risk to public health and safety for the purpose of this section);

~~c) would~~ create an immediate risk of serious damage to facilities or equipment within its electric system or cause it to operate any of its electric facilities or equipment in an unsafe manner;

3)

~~d) would~~ cause the Member to violate or improperly implement an applicable law, regulation, rule, order, FERC license provision or other legal obligation; or

4)

5) ~~e) would~~ conflict with any non-power requirement applicable to the Member (including without limitation any obligation under environmental laws, regulations, court and administrative decisions or biological opinions).

4.7.2 Each Member shall retain sole control of its facilities and the use thereof, and a Member shall not be required to construct or dedicate facilities for the benefit of any other Member, or be required to take action, or refrain from action, as may be

deemed necessary to maintain reliable service to its own customers and/or to fulfill its obligations to third parties; provided, that a Member shall comply with duly-adopted reliability standards applicable to its system and shall comply with any directives under existing security coordination agreements. Nothing in these Bylaws is intended to preclude application of Section 210 or 211 of the Federal Power Act.

4.7.2 4.7.3 The above limitations shall not be construed as altering a Member's obligation, if any, to comply with applicable Reliability Standards or enforcement orders, or any other obligation arising under 18 C.F.R. Part 39.

4.8 **Compliance and Enforcement.**

The power of WECC to enforce Member obligations other than compliance with Reliability Standards and other obligations arising under 18 C.F.R. Part 39 and applicable Canadian and Mexican regulatory requirements is limited to suspension or termination of membership as set forth in this Section; provided, however, that:

1) nothing in this Section will limit the power of Members to agree to additional enforcement provisions in separate contracts (such as contracts pursuant to the Reliability Management System); and

2) nothing in this Section will limit the power of WECC to propose solutions regarding Market Interface issues to any Applicable Regulatory Authority as described in Section 2.1.10; and 3) nothing in this Section will limit WECC's delegated authority under Section 215 of the Federal Power Act and 18 C.F.R. Part 39 and applicable Canadian and Mexican regulatory requirements to enforce Rreliability Sstandards and perform other delegated or contractual functions within the Western Interconnection.

The Board may suspend or, to the extent consistent with applicable law, terminate the membership of any Member for a material failure to meet any obligation of membership set forth in these Bylaws, including, but not limited to:

1) non-payment of dues sixty (60) days after the dues become delinquent;

2) intentionally or repeatedly violating any WECC Bylaw;

3) materially breaching or intentionally violating any FERC Oorder or arbitration decision issued pursuant to these Bylaws;

4) willfully obstructing any lawful purpose or activity of WECC; or

5) remaining inactive as described in Section 5.79.

The Board will give the affected Member not less than twenty-one (21) days prior written notice of any proposed suspension or termination, which will include the specific basis for the proposed action and, if applicable, instructions on curing the problem. Prior to terminating a membership, the Board will consider any information provided by the Member in response to the notice described herein.

4.8.1 Suspension.– The suspension of a Member will not affect the Member's rights and obligations other than that the Member will not be entitled to vote at any meeting of the Members, Classes, subclasses, or any committee until the suspension is removed, except that a suspended Member may participate in the WECC ~~proposed~~ Reliability Standards Development Procedure.

4.8.2 Termination.— The termination of membership will have the same effect, and be subject to the same continuing obligations, as such Member's withdrawal pursuant to Section 4.1, except that it will be effective as of the issuance date of the notice provided pursuant to Section 4.8.

4.9 **WECC Structure and Governance Review.**

At least each five (5) years, the Board of Directors, in collaboration with the Member Advisory Committee and the Western Interconnection Regional Advisory Body, will conduct a thorough assessment of whether WECC ~~is~~ fulfill~~ing~~ its purposes in a manner that is consistent with~~: 1)~~ its mission and vision, and the provisions of Section 2.2 of these Bylaws.~~; and 2) the then-current state and the expected future evolution of the electric power industry within the Western Interconnection. Unless determined otherwise by a majority vote of both the Board of Directors and the Members Advisory Committee (MAC), the initial review required under this Section 4.9 will commence after the completion of the first full year of operation under these Bylaws as amended in June 2013 and will be done collaboratively with the MAC and to the extent practical, will be coordinated with any similar structure and governance reviews being conducted by Peak Reliability. In particular,~~ As part of this assessment, the Board will consider ~~focus on~~ whether the standards, obligations, processes~~,~~ and decisions WECC imposes on its Members are timely, fair, effective, and reasonable in view of the commercial, legal, regulatory, and economic needs and objectives of the affected Members. ~~The Board will evaluate WECC's Board composition, Member Class structure, committee structure and activities, and staff responsibilities as they relate to the foregoing considerations.~~ The assessment required by this Section 4.9 will be accompanied by ~~Board~~ recommendations for any changes the Board determines are warranted by the assessment. If any recommendations require Member approval prior to implementation, –t~~T~~he assessment and recommendations prepared by the Board in accordance with this Section 4.9 will be submitted in writing to the Members at the first A~~a~~nnual M~~ember m~~eeting held after the review~~y are~~ is completed.

5. Procedures for Member Decisions.

5.1 **Quorum and Alternative Voting.**

With the exception of voting on Regional Reliability Standards and Regional Criteria under ~~the oversight of the WECC Standards Committee~~ the Reliability Standard Development Procedures, M~~m~~embers may conduct business and take votes only at duly noticed Member meetings. Members may not conduct any business of the membership as a whole at any meeting unless a quorum is first established.

5.1.1 Quorum.— A majority of all Members, including a majority in at least three (3) Classes, will constitute a quorum for all meetings of the membership as a whole,

including for the election of Directors.~~–~~ A majority of the M~~m~~embers of a Class or subclass will constitute a quorum for all ~~Member~~ Class or subclass meetings. Members participating through a designated A~~a~~lternat~~iv~~e Member R~~r~~epresentative or through submission of an absentee ballot will be counted in determination of a quorum.~~–~~ Inactive Members, as defined in Section 5.7~~9~~ of these Bylaws, will not be counted in determining a quorum at Member, ~~Member~~ Class or subclass meetings.~~–~~ A quorum, once established, will be deemed to continue for the balance of any Member, ~~Member~~ Class, or subclass meeting~~, except that no election of Directors may occur without a quorum being present. Members may designate an alternate representative or submit an absentee ballot in a form consistent with Section 5.1.2 for any Member, Member Class, or subclass meeting~~.

5.1.2 Alternate Member Representative or Absentee Voting.~~:~~ ~~In the event that~~If a Member~~'s designated voting~~ R~~r~~epresentative cannot attend a meeting ~~–~~of the Membership or a ~~Member~~ Class meeting in person where Directors are being elected or amendments to these Bylaws are considered for approval, the Alternate Member Representative may attend and vote in place of the Member Representative. Alternatively, the Member Representative or Alternate Member Representative, may cast an absentee ballot pursuant to procedures established by the Secretary. In the absence of both the Member Representative and the Alternate Member Representative, a Member may designate a Proxy ~~n alternate voting Member representative, with two (2) days written notice to the Corporate Secretary, or a Member may cast an absentee ballot~~ pursuant to the procedures established by the ~~Corporate~~ Secretary.

5.2 **General Membership Meetings.**

All business of the Members acting as a whole will be conducted at meetings called by advance notice to all WECC Members provided in accordance with Section 5.4~~5~~.~~–~~ Unless stated otherwise in these Bylaws, decisions at all meetings of the Members, ~~Member~~ Classes, or subclasses will be by simple majority vote of the Members present or otherwise represented in accordance with these Bylaws, with each Member having one vote, unless other Bylaw provisions provide for the allocation of the Member's vote.~~–~~ The ~~C~~chair of the Board will preside over all general membership ~~Members acting as a whole~~ meetings.

~~5.3~~5.2.1 **Annual Member Meetings.**

WECC will hold an Annual Member Meeting ~~of all Members~~ at a time and place determined by the Board. At the Annual Member Meeting, and at other times as provided for in these Bylaws, in addition to such other actions the Members may take, the Member~~s~~ and Classes will elect D~~D~~irectors for vacant ~~d~~Director positions (as provided in Section 6.4.3).

~~5.4~~5.2.2 **Special Member Meetings.**

Members may hold special meetings whenever called by the Board.~~–~~ The Board will call special Member meetings whenever a majority of the Members of any Class request a special meeting or at such other times as it deems appropriate.~~–~~ The ~~C~~chair of the Board will preside over all special Member meetings.

5.55.3 **Member Class and Subclass Meetings**

An individual ~~WECC Member~~ Class or subclass may hold a meeting for any purpose relevant to the interests of Class or subclass m~~M~~embers.~~–~~ Such meetings will be initiated by request ~~by~~ of one or more Class or subclass m~~M~~ember(s), and agreement by at least fifty (50) percent ~~(50%)~~ of Class or subclass m~~M~~embers.

5.65.4 **Notice of Member Meetings.**

5.6.15.4.1 Annual Member Meeting.~~—~~ The ~~Chief Executive Officer~~ Secretary will provide at least thirty (30) days' ~~advance~~ notice to all Members and the Board of the date, place and time of the Annual Member Meeting ~~of the Members~~ and an agenda of the business to be conducted at such meeting.

5.6.25.4.2 Other Member Meetings.~~—~~ The ~~Chief Executive Officer~~ Secretary will provide notice of regularly scheduled and special meetings ~~of the Members~~ to the Members not less than ~~fifteen (15) days before the meeting if delivered by first-class mail, or not less than~~ ten (10) days before the meeting ~~if the notice is delivered personally, by telephone, by facsimile, electronic mail or express mail. If mailed, such notice will be deemed given when deposited in the United States mail, with first-class postage thereon prepaid, addressed to a Member. Such notice will state the date, time and place of the meeting and the meeting agenda~~.

5.6.35.4.3 Public ~~and Website~~ Notice.~~–~~ Public notice of each meeting of the Members will be placed on WECC's website at least ten (10) days before such meeting~~. In addition, the Chief Executive Officer will provide notice in the same manner and time as set forth in Section 5.6.2 of each meeting to each member of the public who so requests and who has provided appropriate information regarding delivery of notice~~.

5.75.5 **Open Meetings.**

All Members'~~hip~~ meetings are open to observation by the public.

5.85.6 **Policymaking Authority.**

The Board of Directors may adopt policies for the interpretation and implementation of the meeting and voting procedures established in this Section 5.

5.95.7 **Minimum Participation Requirement**.

~~In order t~~To be counted for quorum purposes at a meeting of the M~~m~~embers~~hip~~ as a whole, Class, or subclass ~~meeting~~, a ~~WECC~~ Member must actively participate at least once each calendar year either~~(~~ by attending a WECC meeting ~~in person, sending an alternate,~~ or voting in a WECC election~~absentee) in at least one WECC meeting (including meetings of the Board, committees and subcommittees) each year~~.~~-~~ If the Member does not meet this minimum participation requirement, the Member will be considered an "inactive" Member until its active status is restored by participation ~~in at least one WECC meeting (including meetings of the Board, committees and subcommittees) by attending in person, sending an~~

~~alternate, or voting absentee~~ as described above.~~ -~~ An inactive Member will not be counted toward the total number of Members when establishing a quorum requirement for~~of~~ the M~~m~~embers~~hip~~ as a whole, ~~of~~ a Class, or ~~of~~ a subclass. ~~–A~~n ~~applicant for WECC membership or a WECC~~ Member may at any time ~~self-~~designate itself an inactive Member. Such designation will be effective until the Member is reinstated to "active" status. ~~-~~If a Member does not participate for twenty~~–-~~four (24) consecutive months, the ~~Member's~~ membership will be terminated. ~~-~~If a ~~Member's~~ membership is so terminated, reapplication for membership may be made at any subsequent time.

6. Governance.

6.1 Board of Directors.

Subject to those matters expressly requiring approval ~~of~~ by the Membership, a Board of Directors elected by the Members will govern WECC.~~–~~ The Board ~~of Directors~~ will elect its own c~~C~~hair and v~~V~~ice~~-~~ c~~C~~hair from those individuals serving as Directors.

6.2 Composition of the Board and Board Member Qualifications.

6.2.1 The Board of Directors shall consist of nine (9) Directors.~~–~~ At all times, subject to temporary vacancies, the Board of Directors shall include at least three D~~d~~irectors who each have at least ten years of experience in the utility industry at the senior management or officer level, preferably in the Western Interconnection, including:

1) at least one ~~d~~Director who has transmission operations experience,

2) at least one D~~d~~irector who has transmission planning experience, and

3) at least one D~~d~~irector who has generation operations experience.

~~At any time where the membership of the Member Advisory Committee (MAC) is modified, as may be provided in other provisions of these bylaws, to include representation for Entities of the two Canadian Provinces of British Columbia and Alberta and the Mexican State of Baja California, a~~At least one Director shall possess experience in British Columbia, Alberta, or Mexico, and also be a resident of one these jurisdictions~~, elected subsequent to such MAC representation, shall have international experience corresponding to such geographic area(s) and/or representation in the MAC~~. Notwithstanding the foregoing requirements, or any Director vacancies, the Board of Directors shall at all times retain its authority and ability to govern WECC so long as a properly constituted quorum is established in accordance with section 7.1.

6.2.1.1 Transmission operations experience shall preferably include experience in control center operations.

6.2.1.2 Transmission planning experience shall preferably include experience in modeling and/or planning transmission facilities, including economic and reliability modeling.

6.2.1.3 Generation operations experience shall preferably include experience in development or operation of generation facilities, including economic and reliability modeling.

~~6.2.1.1~~6.2.1.4 Experience in the Canadian provinces of British Columbia and/or Alberta, and/or Mexico shall preferably include, but not be limited to, those types of experience described in sections 6.2.2.1 through 6.2.2.7 below.

6.2.2 The remaining members of the Board of Directors shall be selected ~~in an effort to~~ ensure diversity of background and experience.~~–~~ Desirable categories of experience ~~may~~ include: regulatory or legal; accounting, finance or economics; environmental; end-user advocacy; information technology; compliance or standards; and public sector~~; and international~~.

~~6.2.2.1 Transmission operations experience shall preferably include experience in control center operations at the senior management or officer level.~~

~~6.2.2.2 Transmission planning experience shall preferably include experience in modeling and/or planning transmission facilities, including economic and reliability modeling at the senior management or officer level.~~

~~6.2.2.3 Generation operations experience shall preferably include experience in development or operation of generation facilities, including economic and reliability modeling at the senior management or officer level.~~

~~6.2.2.4~~6.2.2.1 Regulatory or legal experience shall preferably include at least one of the following types of experience: state, provincial or federal industry regulation; significant litigation experience ideally at the appellate level; evaluation of complex legal arguments; and advising clients with respect to settlements.

~~6.2.2.5~~6.2.2.2 Accounting, finance or economic experience shall preferably include experience as a c~~C~~hief f~~F~~inancial o~~O~~fficer, a c~~C~~hief a~~A~~ccounting o~~O~~fficer, a c~~C~~orporate r~~R~~isk o~~O~~fficer, a c~~C~~ertified p~~P~~ublic a~~A~~ccountant, or the equivalent thereof.

~~6.2.2.6~~6.2.2.3 Environmental experience shall preferably include experience advocating environmental interests before local, state or federal agencies or boards, and/or leadership experience in representing environmental interests in relation to energy issues.

~~6.2.2.7~~6.2.2.4 End-user advocacy experience shall preferably include experience advocating end-user economic interests before local, state or federal ratemaking agencies or boards.

~~6.2.2.8~~6.2.2.5 Information technology experience shall preferably include experience as a senior ~~–~~level manager responsible for integrating information technology services with organizational needs in areas such as capacity planning, budget and finance, acquisition and deployment, operations, change management, application development, trade ally relationships, user support, data quality, security and similar areas.

~~6.2.2.9~~6.2.2.6 Compliance or standards experience shall preferably include experience as a senior level officer or manager for corporate compliance with internally and/or externally imposed requirements, rules or standards.

~~6.2.2.10~~6.2.2.7 Public sector experience shall preferably include experience representing the public interests with respect to energy issues.

~~6.2.2.11 International experience shall preferably include experience as described in the previously listed experience categories, but in the Canadian provinces of British Columbia or Alberta, or the Mexican state of Baja California.~~

6.2.3 Director Affiliation Restrictions.~~–~~ A Director may not be a full~~-~~time employee of a Registered Entity.~~—~~ Nor may a Director be affiliated with any Member or Registered Entity operating in the Western Interconnection~~, nor a Director of an entity performing the function of Reliability Coordinator in the Western Interconnection~~.

6.2.3.1 For the purposes of this section, "affiliated" shall mean (1) an employee of, (2) a contractor for, (3) an employee of a contractor for, or (4) an equity owner of or a Director for a Registered Entity or Member.~~–~~ For purposes of determining whether a Director is "affiliated" the term "Director" shall include a spouse and/or minor child of the Director.

6.2.3.1.1 A Director with an equity interest in private or publicly traded companies that are end-users of electricity in the Western Interconnection but ~~are~~who is not otherwise "affiliated" pursuant to the restrictions set forth in Section 6.2.3~~2~~ shall not be considered ~~to be~~ "affiliated.~~"~~.

6.2.3.1.2 A Director with an equity ownership in a broadly diversified mutual fund which may ~~from time to time~~ include interests in one of the types of organizations described in Section 6.2.3~~2~~, shall ~~"~~not be considered ~~to be "~~affiliated~~,~~ provided that such equity interest cannot confer a controlling interest in a Member or Registered Entity within the Western Interconnection.

6.2.3.1.3 A Director receiving post-employment compensation, which compensation is not indexed to the success of the disbursing entity shall not be considered "affiliated.".

6.2.3.1.4 A Director shall not be considered "affiliated" solely by having a contractual relationship with a state government that has one or more agencies that are Members, provided that the Director cannot be affiliated with the Member agency or agencies.

6.2.3.1.5 A Director shall not be considered "affiliated" for being a residential or small business end-user of electricity or for being affiliated with, a member of, or a contributor to an organization that represents a substantial number of end users or a substantial number of persons interested in the impacts of electric systems on the public interests or the environment, but a Director shall be considered "affiliated" if the Director is an employee of, or serves as a director, trustee, or officer or in any other policy-setting capacity with respect to any such organization.

6.2.3.2 The affiliation restrictions set forth in this Section are not all encompassing. Candidates and Board members are expected to disclose all known potential financial or relationship conflicts, including any known relationships between companies they have affiliation with and/or entities described in Section 6.2.32. Furthermore, any the Nominating Committee will be expected to investigate and evaluate all potential conflicts, whether financial or otherwise.

6.2.4 In addition, the Board may, by resolution, appoint provide for the Chief Executive Officer ("CEO") of WECC to be a voting, additional tenth, member of the Board, provided that through the inclusion of such a provision in the resolution the Board adopts appointing WECC's CEO. Such provision shall not permit the CEO may notto be a member of a Board committee or to cast either a tie-breaking vote or a vote that creates a tie. The CEO may not serve as the Cchair or Vvice Cchair of the Board.

6.3 **Term of Office.**

Directors will hold office for staggered terms of three (3) years, three Directors' terms ending each year. Each three (3) year term shall commence, and subsequently end, upon the adjournment of the portion of the Annual Member Meeting provided for in Section 5.3, in which all Members are counted for purposes of determining a quorum. Similarly, the three year terms of outgoing Directors shall end upon the adjournment of that portion of the Annual Member Meeting in which all Members are counted for purposes of determining a quorum,. This may result in some Director terms that arewhether that results in a longer or shorter term than exactly three years.

6.4 **Nomination, Selection and Compensation of Directors.**

6.4.1 Nominating Committee.– Candidates for a Director position shall be nominated by a Nominating Committee.— The Nominating Committee shall consist of seven members. Three voting members shall be Directors, ~~not standing for re-election,~~ designated by the Board ~~C~~chair, whose terms are not expiring at the next Annual Member Meeting.— The remaining four voting Nominating Committee members shall be ~~designated by the~~ Member Advisory Committee members selected by the MAC~~and come from individuals serving on the Member Advisory Committee~~, with two (2) members being from Classes 1, 2, and/or 3, and two (2) members being from Classes 4 and/or 5. The MAC shall also select, as non-voting members of the Nominating Committee, an international member and one member from each of the Classes that are not voting members of the Nominating Committee. Quorum for the Nominating Committee will be a majority of voting members.

6.4.1.1 If the Member Advisory Committee does not designate MAC members to serve on the Nominating Committee within 30 days of being notified of the Board c~~C~~hair's designation of the three Directors to serve on the Nominating Committee, the Board c~~C~~hair may designate MAC members to serve.

6.4.1.2 A Nominating Committee shall be formed each year not less than 180 days prior to the Annual Member Meeting.— A Nominating Committee will continue to function until a replacement Nominating Committee is formed, but may not continue for a period longer than twelve (12) months from its creation, ~~provided however, that~~unless the Board, by resolution, ~~may~~ authorizes a Nominating Committee to function beyond twelve (12) months ~~as the Board may determine is necessary~~.

6.4.2 Director Candidate Nominations.

6.4.2.1 The Nominating Committee shall develop candidate pools and make candidate nominations to the Members.– The Nominating Committee may consider any qualified applicant in developing the candidate pool, and may identify applicants through the following process:

1) selecting and ~~utilizing~~ using an independent search firm to provide the Nominating Committee with a list of qualified applicants for each Director position subject to election;
2) consider an incumbent Director who is willing to stand for reelection, including a review of such Director's tenure on the Board of Directors; and
3) consider external nominations.

6.4.2.2 Any ~~External~~ party~~ies, including but not limited to Members and Western Interconnection stakeholders,~~ may recommend candidates (self-

recommendations and third-~~party~~ party recommendations) to the Nominating Committee for consideration, by submitting the following:

- the candidate's resume,
- a summary of the candidate's relevant experience,
- a disclosure statement from the candidate, and
- a letter of interest from the candidate.

~~A~~All candidate recommendations ~~from external parties~~ must be submitted to the Nominating Committee no later than the deadline established by ~~within sufficient time for~~ the Nominating Committee ~~to evaluate the candidate prior to the notification required in Section 6.4.2.5~~.

6.4.2.3 The Nominating Committee shall review the qualifications of the potential candidates and put forth one nominee for each Director position up for election.

6.4.2.4 Five (5) affirmative votes of the Nominating Committee shall be necessary to put forth a nominee for election by ~~to~~ the Members.

6.4.2.5 At least sixty (60) days in advance of the Annual Member Meeting, the Nominating Committee chair shall forward the list of nominees to~~notify~~ the Board c~~C~~hair~~.~~ The Nominating Committee chair shall advise the Board chair if the Nominating Committee is unable to agree on a complete list of nominees ~~whether or not it has finalized all Director nominations~~.~~If the Committee fails to put forth a nomination for an open position, then t~~The Board c~~C~~hair may form a new Nominating Committee with different Board and ~~Member Advisory Committee~~MAC members~~,~~ who shall be tasked with ~~developing any remaining nominations~~ nominating candidates for the remaining open Director positions.

~~6.4.2.6 Each nominee, put forth by the Nominating Committee, shall be presented for separate election by the Members.~~

6.4.3 Director Elections. Members will vote for each ~~vacant Director position~~nominee separately. A candidate will be elected to the Board ~~up~~on receiving a majority vote of the Members as a whole in addition to a majority of the Classes (three of the five) having a majority vote from the Members of the individual Class.

Should a candidate fail to receive the required vote of the Members or Member Classes, the Board may~~:~~ conduct a new election ~~of~~ for an alternate candidate put forward by the Nominating Committee, if any~~.~~~~,~~ Alternatively,~~or~~ the Board may ask the Board c~~C~~hair to establish a new Nominating Committee to recommence the nomination and election process.~~—~~ Where a candidate has not received the required vote of the Members and ~~Member~~ Classes, the D~~d~~irector position shall remain vacant until a candidate is elected, except as provided in

Section 6.7.2
~~6.4.3.1~~

6.4.3.1 Election by Members Without a Meeting. Member elections for Directors may occur in conjunction with an Annual or Special Member Meeting as described elsewhere in these Bylaws, or voting may occur in whole or in part through submission of written or electronic ballots in accordance with procedures determined by the Secretary to ensure the integrity of the voting process.

6.4.4 Annual Compensation of Directors. Each year the Nominating Committee will make an Director compensation recommendation for the following calendar year. ~~Every two years, or sooner if, in the discretion of the CEO, a new survey is required, the CEO shall contract with an appropriate firm to conduct a national compensation survey, which shall provide an independent review of the compensation paid independent directors~~The Board shall direct WECC staff to initiate a Director compensation study for the Nominating Committee every other year.~~–~~ The latest survey so procured shall be used by the Nominating Committee ~~to make an~~in formulating its annual compensation recommendation, which shall provide an independent review of Director compensation ~~for the compensation of Directors for the following year~~.~~–~~ Any such recommendation shall require five (5) affirmative votes of Nominating Committee members.~~—~~ This recommendation shall be presented to the MAC no later than one hundred fifty (150) days prior to the Annual Member Meeting.~~–~~ The MAC shall set the compensation for the Directors at least one hundred and twenty (120) days prior to the Annual Member Meeting.~~–~~ When making this decision, the MAC shall consider the recommendation of the Nominating Committee and any other material relevant to setting Director compensation.~~–~~ If the Nominating Committee is unable to reach the five (5) vote majority necessary to make a compensation recommendation, the MAC shall make no changes to the compensation paid Directors for the following calendar year.

6.5 **Removal of Directors.**

The Members or the Board may remove a Director before completion of the Director's term of office pursuant to the following provisions.

6.5.1 Removal by the Members.~~–~~ Directors may be removed only for gross negligence, violation of local, state, provincial, or federal laws, gross misconduct, or failure to meet the fiduciary obligations of Directors.

6.5.1.1 Removal of a Director will be by a vote of a majority of all the ~~WECC~~ Members, not just those Members voting, in addition to a majority ~~of the Classes (~~vote from at least three of the five~~)~~ Classes ~~having a majority vote from the Members of the individual Class~~.~~–~~ Removal may only take place at a meeting called for that purpose by notice provided in accordance with the notice requirements for M~~m~~ember meetings.~~–~~ A vote~~, by all Members,~~

to consider removal of a Director will occur based ~~up~~on submission to the Secretary of a petition~~,~~ for such a~~n all Member~~ vote~~, supported~~ signed by the Member Representatives of~~by~~ at least ~~twenty~~ 20 percent ~~(20%), each,~~ of the Members in~~of~~ three of the five ~~Member~~ Classes.

6.5.2 Removal by the Board.~~–~~ The Board may remove any Director for gross negligence~~;,~~ violation of local, state, provincial, or federal laws~~;,~~ gross misconduct~~;,~~ or failure to meet the fiduciary obligations of Directors. Such removal will only occur upon the affirmative vote of not less than six (6) Directors.

6.6 **Resignation.**
Any Director may resign ~~from their position~~ at any time by written notice to the Board ~~by~~ deliver~~ed~~~~y~~ to the Board ~~C~~chair.~~–~~ The acceptance of a resignation will not be required to make it effective.

6.7 **Procedures for Filling Vacant Director Positions.**

6.7.1 Director Vacancies.~~—~~ If the position of any Director becomes vacant prior to its normal term expiration~~,~~ and there is more than one (1) year remaining in said term, the ~~remaining Directors may charge the~~ Nominating Committee will~~—~~within a reasonable amount of time~~—~~begin the process of choosing ~~with selecting~~ a successor ~~immediately~~candidate for nomination and election. The applicable requirements of this Section 6 shall apply to this nominating process, except those regarding the timing of certain actions. The Nominating Committee chair shall advise the Board chair of the Nominating Committee's nomination. If, within six (6) months of the occurrence of a vacancy, the Nominating Committee has failed to notify the Board chair of a nominee for that vacancy, the Board chair shall appoint a new Nominating Committee, with different Board and MAC members, which will commence work immediately to select a nominee for said vacancy. ~~The Nominating Committee will follow the requirements set out in Sections 6.2.1 and 6.2.2 in its selection of any successor Director.~~ Alternatively, if less than one (1) year remains in the term of ~~that~~ the vacant Director position, the position will remain vacant, unless a temporary Director is appointed as permitted by section 6.7.3, until filled in conjunction with the typical annual Director nomination and election processes described elsewhere in this Section 6~~remaining Directors may choose to leave the position vacant for the remainder of the term~~.

6.7.2 Holdover to Cure Procedural Vacancies.~~—~~ Whenever an incumbent Director is a candidate for a Director position and is not re-elected due to a lack of quorum or other procedural deficiency, ~~a vacancy would be created due to expiration of the Director's term, the~~that Director may continue to serve, for no more than ~~up to an additional~~ twelve (12) months from the original expiration date of the Director's term, until ~~such time as~~ a~~n~~ valid election ~~of the Director's position can~~ has be~~en~~ conducted~~, provided the vacancy arises from a lack of quorum or other procedural inability to elect a candidate for the Director position~~.

6.7.3 Should the number of serving Directors fall below seven (7), the Board may appoint one or more individuals to serve as temporary Directors until ~~such time as~~ replacement Directors can be elected by the Members.

6.7.3.1 In appointing temporary Directors, the Board shall select individuals whose experience ~~meet the requirements~~ensures the Board composition requirements of Section 6.2 are satisfied.

6.8 **Duties of Directors.**
The Directors will have the following duties:

6.8.1 Fiduciary Obligation to WECC: All Directors, will have a fiduciary obligation to WECC consistent with the requirements for Directors of Utah non-profit corporations.~~–~~ Members of the Board will at all times act in conformance with such requirements, these Bylaws and the Standards of Conduct set forth in Appendix A.

6.8.2 Preserve Non-Affiliated Status: Throughout their terms, Directors will have a duty to avoid any affiliation that is inconsistent with the qualifications for Directors in Section 6.2.2 of these Bylaws.~~—~~ If a Director becomes aware of any intervening disqualification, he/she must either resign or eliminate the disqualification (e.g., dispose of securities) within sixty (60) days.

6.9 **Powers of Directors.**
The management of all the property and affairs of WECC ~~will be~~is vested in the Board of Directors.~~—~~ The Board will hold annual elections to select a Board c~~C~~hair and vice chair and to fill any other Board officer positions that may be created by the Board or required by applicable law.~~—~~ The Board may exercise all the powers of WECC and do all lawful acts and things (including the adoption of such rules and regulations for the conduct of its meetings, the exercise of its powers and the management of WECC) as are consistent with these Bylaws and the Articles of Incorporation.~~—~~ When deliberating policy matters, t~~T~~he Board will give serious consideration to the recommendations of the Member Advisory Committee~~'s~~ and the Western Interconnection Regional Advisory ~~Board's~~ Body (or any successor) ~~recommendations. The Board will respond to Member Advisory Committee and Western Interconnection Regional Advisory Board recommendations through a means which the Board determines appropriate~~.

6.10 **Delegation of Board Authority.**
The Board may delegate to ~~the Chief Executive Officer or to~~ any person or any ~~Board c~~Committee ~~formed pursuant to Section 7.7.3~~ any or all of its powers and authority except ~~:~~

~~1)~~ any power ~~which~~that it may not delegate pursuant to applicable Utah law, and the power to~~;~~:

~~2~~1) ~~the power to~~ adopt any ~~r~~Reliability ~~s~~Standard;

~~3~~2) ~~the power to determine when to exercise the Backstop Authority of WECC; 4) the power to~~ approve budgets;

3~~5~~) ~~the power to~~ form committees;

4~~6~~) ~~the power to~~ amend the Bylaws;

5~~7~~) ~~the power to~~ elect the Board ~~C~~chair and other officers of the Board; and

7~~8~~) ~~the power to~~ hire, fire or set the terms of employment of the Chief Executive Officer.~~.~~

These powers are ~~The Board may also delegate to any Member committee the power to make specific decisions,~~ subject to the right of any Member to appeal any of such decisions to the Board within 30 days of the committee vote on the decision by writing a letter to the Chief Executive Officer that describes in reasonable detail the grounds for appeal, and requests that the appeal be considered by the Board at its next regularly scheduled meeting, subject to applicable notice requirements.~~—~~ Delegation will be by resolution~~express decision and will require the affirmative vote of not less than a majority of the Directors~~. Any Director may call for a vote to rescind such delegation at any time ~~and such delegation will be rescinded if a majority of the Directors vote to do so~~.

6.10.1 Notice to Members.~~–~~ Within seven (7) days of any decision delegated to a Member committee pursuant to Section 6.10, the subject Member committee must notify all ~~except for routine decisions of the Chief Executive Officer,~~ Members ~~will be notified~~ of the decision by electronic mail, posting on the WECC website and any other means determined appropriate by the Board.~~–~~ ~~Routine decisions of the Chief Executive Officer will be noticed in periodic reports to the Board and Members as determined by the Board, which will be sent to Members by electronic mail and posted on the WECC website.~~

6.10.2 Board Review of Delegated Decisions.~~–~~ Decisions delegated pursuant to Section 6.10 will be reviewed by the Board at the request of any Director, provided such request is lodged with the Secretary within thirty (30) days of the notice.~~–~~ Whenever it determines that a matter requires an urgent decision, the Board may shorten the deadline for requests for review, provided that: 1) the notice and opportunity for review will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for Board review. A request for review of a decision will stay the effect of the decision pending review unless the Board in making the delegation expressly determines otherwise.

7. Procedures for Board Decisions.

7.1 Quorum.

No business will be conducted by the Board unless at least five (5) Directors are present, or six (6) Directors if the CEO is counted to determine a Board quorum.

7.2 Majority Vote.

A decision of the Board will require an affirmative vote of a majority of Directors present and not abstaining; provided that no decision of the Board shall be made with fewer than three (3) affirmative votes, or four (4) affirmative votes if the CEO is counted to determine

a Board quorum.~~–~~ Directors may not vote by proxy or by absentee ballot, but Directors may participate in Board meetings ~~by telephone~~ as provided in Section 7.3 of these Bylaws.

7.3 **Attendance at Board Meetings by Teleconference.**

Any or all of WECC's Directors may participate in any meeting of the Board by telephone conference or any other means of communication that enable all Directors participating in the meeting to simultaneously hear one another.~~–~~ Every Director participating in a meeting in the manner described in the preceding sentence will be deemed to be present in person at that meeting.

7.4 **Board Action by Unanimous Consent.**

~~7.4.1 Action Without a Meeting.~~ Unless WECC's Articles of Incorporation or applicable law provides otherwise, action required or permitted to be taken at a meeting of the Board may be taken without a meeting through one or more written consents describing the action taken.~~–~~ Any Board action taken by written consent must be signed by all Directors in office at the time the action is taken. Such actions require three (3) business days' prior notice~~must be noticed~~ to Members ~~in accordance with Section 7.5~~ and Members must be given an opportunity to comment ~~prior to the Board taking such actions~~ through electronic mail, comments on the website or other appropriate means. ~~The required notice of such meeting may generally describe the arrangements (rather than the place) for the holding of the meeting. All other provisions herein contained or referred to will apply to such meeting as though it were physically held at a single place.~~ All Board actions by written consent must be filed with WECC's Board meeting minutes.~~–~~ Action taken under this Section is effective when the last Director signs the consent, unless the consent specifies an earlier or later effective date.~~–~~ Any action by written consent has the same effect as a meeting vote and may be described as such in any document.

~~7.4.1 Waiver of Procedures. For any specific action at any noticed meeting of the Board, and under exigent or unusual circumstances, the Board by unanimous vote of those present may waive any procedural requirement applicable to Board decision-making, including any requirement for notice of a specific potential action, except for the following: 1) the requirement for notice of the time and place of the meeting pursuant to Section 7.5; 2) the quorum and voting requirements of Sections 7.1 and 7.2; and 3) any non-procedural limitation on the power of the Board to make a decision, including, but not limited to, those restrictions in Sections 6.10 (limiting the power to delegate) and 12.1 (limiting the power to amend the Bylaws). Whenever such action is taken, a statement describing the action, the exigent or unusual circumstances, the specific procedure waived, the basis for the waiver and the votes of all Directors present shall be posted on the website and communicated in writing or by e-mail to all Members within five (5) days.~~

7.5 **Notice of Board Meetings.**

7.5.1 Regular Meetings. Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at ~~the~~ Board meetings, at least twenty-

one (21) days' ~~advance~~ notice of which has been provided by the ~~Chief Executive Officer~~Secretary to all Directors and all Members via email and posting to the WECC website.~~–~~ Notice will include an agenda that will identify those matters on which a vote will be taken at the meeting.~~–~~ The foregoing requirement shall not preclude the Board from taking an action that is different from the specific proposed action identified in the agenda, ~~as long as~~if the relevant subject matter has been reasonably identified in the agenda.~~–~~ The Directors will establish a regular meeting schedule that will be made available to the Members.~~–~~ The schedule will include not less than two meetings of the Board annually.

7.5.2 Special Meetings. Whenever the Board c~~C~~hair ~~of the Board~~ or any three (3) Directors find that there is urgent business requiring Board action before the next regular Board meeting, a special meeting of the Board may be called. Such special meetings will be held upon as much written notice to each ~~Board Member~~Director and all Members as is possible under the circumstances, ~~which will not~~but shall be no less than three (3) days. However, ~~this~~ notice of a special meeting~~s~~ may be waived if: 1) the waiver is by a writing signed by a quorum of ~~Board members~~Directors; and 2) as much notice of the meeting as practicable has been given to ~~WECC~~ Members via e~~lectronic~~ mail and post~~ed~~~~ing~~ on the WECC website.

~~7.5.3 Public and Website Notice. Public notice of each meeting of the Board will be placed on WECC's website at least ten (10) days before such meeting (or such lesser time as provided pursuant to Section 7.5.2). In addition, the Chief Executive Officer will provide notice of each meeting by first-class mail, facsimile or electronic mail to each member of the public who so requests and who has provided appropriate information regarding delivery of notice.~~

7.6 **Open Meetings.**

Except as provided in Section 7.6.1, all regular and special meetings of the Board will be open to observation by any Member and any member of the public.

7.6.1 Closed Session.~~—~~ Notwithstanding the provisions of Section 7.6, ~~up~~on an affirmative vote of two-thirds (~~⅔~~2/3) of the Directors present, the Board may meet in closed session:

1) to consider the employment, evaluation of performance, or dismissal of an employee of WECC and to deliberate regarding decisions the Board may be called upon to make regarding the nomination, qualification, appointment, or removal of a member of the Board of Directors;

2) to discuss pending or proposed litigation ~~and~~ or to receive other confidential attorney-client communications from legal counsel; and

3) to receive and discuss any information that is privileged, trade secret, cybersecurity, critical energy infrastructure information (as defined by the FERC), protected from public disclosure by law or that the Board determines should be confidential ~~in order~~ to protect a legitimate public interest.

7.6.1.1 Attendance by an Affected Director. Closed sessions of the Board may not be attended by a Director under the following circumstances:

1) where the qualifications or performance of the Director or the Director's spouse or children are being discussed;

2) where the Director is employed by an entity that is or is likely to become a party to the litigation being discussed; and

3) where the Director or the Board determines that the Director would have a serious and substantial conflict of interest by becoming privy to confidential attorney-client or trade secret information that is to be presented to the Board in closed session.

7.6.1.2 Announcement of Closed Session. Before adjourning into closed session, the Board ~~C~~chair ~~of the Board~~ will announce the purpose of the closed session in a manner that provides the public an understanding of the general subject matter to be discussed but which does not reveal sensitive or personal information. The Board will not discuss additional items outside the scope of this description.

7.6.1.3 Confidentiality of Closed Session. All Directors and others present will maintain the confidentiality of discussions and decisions made in closed session. The Board will appoint a secretary for each closed session to keep ~~a~~ minutes, ~~book for the purpose of~~ recording the subject matter discussed in closed session and any actions taken in closed session. After a closed session has ended, the Board ~~C~~chair shall provide the public a general description of the business conducted during the closed session, without breaching the confidentiality of the information used in the session.

~~7.7 **Board Committees.**~~

~~7.7.1 Governance Committee. The Chair will appoint a Governance Committee that shall: oversee implementation and amendment of these Bylaws and address such other issues pertinent to Governance as the Board may choose to delegate to it. The Chair will designate one of the appointed Directors to be the Chair of the Governance Committee.~~

~~7.7.2 Nominating Committee. Constituted as described in Section 6.4.1 of these Bylaws.~~

~~7.7.3 Other Board Committees. The Board may appoint such Board committees as it deems necessary from time to time to carry out its business affairs. In appointing such committees, the Board will specify their purpose, membership, voting, notice and meeting procedures and such other direction as the Board may deem appropriate. The Board may appoint one or more Members or other persons to participate in Board committees as full voting members or as non-voting advisory members.~~

~~Standards of Conduct for Board Committee Members. Members of Board committees shall comply with the Board Member Standards of Conduct set forth in Appendix A.~~

~~7.8~~7.7 **Waiver of Procedures.**

For any specific action at any noticed meeting of the Board, and under exigent or unusual circumstances, the Board by unanimous vote of those present may waive any procedural requirement applicable to Board decision-making, including any requirement for notice of a specific potential action, except for the following:

1) the requirement for notice of the time and place of the meeting pursuant to Section 7.5;
2) the quorum and voting requirements of Sections 7.1 and 7.2; and
3) any non-procedural limitation on the power of the Board to make a decision, including, but not limited to, those restrictions limiting the power to delegate and limiting the power to amend the Bylaws.

Whenever such action is taken, a statement describing the action, the exigent or unusual circumstances, the specific procedure waived, the basis for the waiver and the votes of all Directors present shall be posted on the website and communicated in writing or by e-mail to all Members within five (5) days.

8. ~~Member~~ Committees.

WECC will have the following committees:

~~8.1 **Purpose.**~~

~~WECC will have committees composed of its Members to advise and make recommendations to the Board. Such committees will include both standing committees required by these Bylaws and such other committees as the Board may choose to create.~~

~~8.2~~8.1 ~~**Standing**~~ **Member Advisory Committee~~s~~.**

~~WECC will have the following standing committees:~~

The Member Advisory Committee (MAC) shall be constituted and operated in accordance with a charter approved by the Board. ~~This committee is comprised of Member representatives elected by the Member Classes, or subclasses, as set forth herein.~~

~~The committee~~ In accordance with ~~said~~ its charter, the MAC shall advise the Board on any matters the Board requests the committee to evaluate or consider~~;~~ and advise the Board on policy, business planning, and budgetary matters as the committee deems appropriate.

8.1.1 The committee shall be comprised of three representatives from each of the five (5) Member Classes, and one representative each for British Columbia, Alberta, and Mexico.

~~8.2.1.1 The committee's Chair or designee will attend the Board's meetings to provide advice, clarifications or respond to Directors' questions. The Board~~

~~Chair and committee Chair shall develop guiding principles and procedures as necessary, to ensure open, effective, and efficient dialog between the MAC and Board. Such guiding principles and procedures may be amended by the Board and committee's Chairs.~~

8.1.2 Reporting to the Board. The MAC Chair, or designee, shall provide a report to the Board at each Board meeting detailing the business carried out by the MAC, and advising the Board of MAC recommendations on matters as set forth in Section 8.1 herein. If there are dissenting MAC member opinions regarding a matter in which the MAC is advising or providing recommendations to the Board, the MAC Chair, or designee, shall present dissenting opinions and rationales in conjunction with the respective MAC advice or recommendations.

~~8.2.2 WECC Standards Committee. This committee will oversee the process for responding to requests for Regional Reliability Standards and Regional Criteria in accordance with the Reliability Standards Development Procedures. The WECC Standards Committee is responsible for determining if a request for a Regional Reliability Standard or a Regional Criteria is within the scope of WECC's activities, and for overseeing the drafting, comment and voting process for a Regional Reliability Standard or Regional Criteria. The WECC Standards Committee shall also oversee the process for responding to requests for interpretations of Regional Reliability Standards and Regional Criteria. The WECC Standards Committee shall consist of one member from each of the WECC Standards Voting Sectors set forth in the Reliability Standard Development Procedures, and a member of the WECC Board who shall act as chair of this committee. The WECC Board shall approve a Charter for the WECC Standards Committee that describes the WECC Standards Committee membership selection process.~~

~~8.2.3 Planning Coordination Committee. This committee will advise and make recommendations to the Board on all matters within the jurisdiction of WECC pertaining to maintaining reliability through evaluating generation and load balance and the adequacy of the physical infrastructure of the interconnected Bulk Electric System within the Western Interconnection.~~

~~8.2.4 Operating Committee. This committee will advise and make recommendations to the Board on all matters within the jurisdiction of WECC pertaining to maintaining reliability through the operation and security of the interconnected Bulk Electric System in the Western Interconnection.~~

~~8.2.5 Market Interface Committee. This committee will advise and make recommendations to the Board on the development of consistent Market Interface practices and compatible commercial practices within the Western Interconnection. It will consider matters pertaining to the impact of WECC's reliability standards, practices, and procedures on the commercial electricity market in the Western~~

~~Interconnection, and facilitate analysis of the impact of electricity market practices on electric system reliability.~~

8.2 **Nominating Committee**

The Nominating Committee shall be constituted and operate as described in Section 6.4 of these Bylaws.

8.3 **Other Committees.**

The Board may establish Committees to advise and make recommendations to the Board related to accomplishing Reliability West's mission within the Western Interconnection. The membership, responsibilities, and operation of all Committees shall be described in a Board-approved charter which may contain such other details pertinent to the governance and functioning of the committee as the Board deems appropriate ~~create such other committees as it may desire from time to time. The Board will specify the functions, duties and responsibilities of any such committee at the time of its creation. The Board will also specify the membership rules, quorum requirements, voting levels and meeting and notice requirements at the time of creation. Any changes in the membership rules, quorum requirements, or voting levels of a committee, once established by the Board, will require a seventy-five percent (75%) vote of the Board to alter. The specific function or sunset date for a committee will be designated by the Board at the time of the committee's creation. The committee will terminate its activities upon the completion of its function or the expiration of the date set by the Board~~.

~~8.4 [Repealed]~~

~~8.5 **Procedures for Member Advisory Committee Decision-Making.**~~

~~8.5.1 Member Advisory Committee (MAC). The committee shall be comprised of three representatives from each of the five (5) Member Classes, for a total of fifteen (15) members.~~

~~8.5.1.1 The Board, by resolution, may create up to three additional representative positions on the MAC, to include representation for Entities of the Canadian Provinces of British Columbia, and/or Alberta, and/or the Mexican State of Baja California. The Board resolution shall set forth the terms through which Canadian or Mexican representatives shall be selected and serve.~~

~~8.5.2 MAC Member Elections. At the Annual Members Meeting, each Member Class shall conduct elections to elect Class member representatives for the committee. As set forth herein, each Class may subdivide into up to three subclasses for purposes of electing a Class' MAC members.~~

~~8.5.2.1 Committee member terms. Each committee member will serve a three year term. Terms shall be staggered such that one of each Class' representative~~

committee member's terms ends each year. Class committee members may have term limits as determined appropriate by the Class or subclass electing such committee member.

8.5.2.2 Subclasses. Each Class will determine the need for diversity within the Class (e.g., geographic, stakeholder issues, etc.) which may lead to the establishment of subclasses. A Class may subdivide into up to three subclasses. Each Class shall determine to establish or discontinue its subclasses, if any, by majority vote of the members in the Class.

8.5.2.3 Committee member nominations and elections. Only members of each Class, or subclass, if applicable, may nominate and vote on candidates for election as a MAC member representative for their respective Class or subclass.

8.5.2.3.1 A Class or subclass candidate need not be a member of the Class or subclass, neither an employee of a Class or subclass member.

8.5.2.3.2 A quorum of a majority of the members of a Class or subclass must be present in order to elect a MAC member for the Class or subclass; election shall be by simple majority of votes cast.

8.5.2.3.3 Where there are more candidates for election than positions to fill, absentee ballots shall allow voters to order the candidates by order of preference so that their wishes may be honored in case a runoff is required. Absentee ballots shall be counted in the first ballot based on the top choice, or the top two or three choices if more than one seat is being filled. In any runoff election, absentee ballots shall be counted based on the highest preferences indicated for the candidates who remain in the runoff election.

8.5.2.3.4 Other nomination and election procedures, beyond those contained in these bylaws, may be proposed for a Class or subclass. Contingent upon their approval, by the General Counsel, for their submission to Members, they may be adopted for implementation by majority vote of the Member Class or subclass.

8.5.3 MAC Member Vacancy by Resignation or Removal

8.5.3.1 Resignation. At any time, any MAC member may resign from their position by providing written notice of resignation to the MAC Chair. Such notice shall be effective as of the date the notice is submitted to the MAC chair.

8.5.3.2 Removal. The MAC or the Member Class or subclass which elected a MAC member may remove the MAC member prior to completion of the Mac member's term of office as set forth herein:

8.5.3.2.1 Removal by the MAC. The MAC may remove any MAC member for gross negligence, gross misconduct, violation of local, state, provincial, or federal law, or gross failure to carry out the duties of a MAC member. Such removal will only occur after the affirmative vote of at least two-thirds (2/3) of the MAC members.

8.5.3.2.2 Removal by the Electing Class or Subclass. The electing Member Class or subclass may remove any MAC member representing that respective Class or subclass. Such removal will occur after the affirmative vote of a majority of the Members of the electing Class or subclass.

8.5.3.3 Vacancy. Whenever a MAC vacancy occurs, the MAC Chair shall conduct a proper and effective election, allowing for a reasonable period to select candidates and to organize such an election.

8.5.3.3.1 Whenever a MAC vacancy occurs, the MAC Chair shall, as promptly as feasible, conduct an election consistent with these Bylaws for the Member Class or subclass from which the vacancy arose, allowing for a reasonable period to select candidates and to organize such an election.

8.5.3.3.2 Until an election can be held, the MAC Chair may appoint an interim MAC member to fill the vacancy as may be required to meet the MAC quorum requirements of 8.5.8. The appointee shall serve until an effective election can be held. Any interim appointment must come from Members of the same Class or subclass from which the vacancy arose.

8.5.4 MAC officers. At the Annual Meeting, after incoming MAC members have been duly elected by the Member Classes or subclasses, if applicable, the MAC will elect the MAC Chair and MAC Vice-Chair from the MAC members. The Chair and Vice-Chair must represent different Classes, and shall serve one year terms, measured from the Annual Meeting to the next Annual Meeting. In the event of the resignation or removal of the Chair or Vice-Chair, the MAC members shall, at their next regular or special meeting, whichever is sooner, elect a new MAC Chair or MAC Vice-Chair, respectively.

8.5.5 MAC Member Duties. All MAC members shall have a duty to represent the interests of their Member Class or subclass. All MAC members shall maintain regular contact with the members of their Member Class as issues are considered by the MAC, and shall make reasonable good faith efforts to present and discuss both majority and minority opinions from their Member Class on matters before the MAC.

~~8.5.6 Regular and Special Meetings.~~

~~8.5.6.1 Regular meetings. All regular business of the MAC shall occur at MAC meetings which are noticed pursuant to Section 8.5.7. The MAC shall meet in person not less than two times per year, including once in conjunction with the Annual Meeting. The MAC shall establish a regular meeting schedule, which will be made available to the Members and Directors electronically, and available to the public through posting on the WECC website.~~

~~8.5.6.2 Special Meetings. Whenever the MAC Chair finds, or upon request to the MAC Chair from any five (5) MAC Members, that there is urgent business requiring MAC consideration or action prior to the next regularly scheduled meeting, then a special meeting shall be called with notice given in accordance with Section 8.5.7.~~

~~8.5.7 Notice.~~

~~8.5.7.1 Regular Meetings. All regular meetings of the MAC shall require at least ten (10) days written notice to the MAC members, the Directors, and the Members. Such notice shall specify the time and place of the meeting, and an agenda of the business to be conducted including those matters upon which a vote will be taken. Notice of regular MAC meetings shall be effective upon electronic distribution, and shall be posted to the WECC website within one (1) business day of electronic distribution.~~

~~8.5.7.2 Special Meetings. Any special meetings of the MAC shall require at least ten (10) days written notice to the MAC members, the Directors, and the Members. Such notice shall specify the time and place of the meeting, and an agenda of the business to be conducted, including those matters upon which a vote will be taken. Notice of special MAC meetings shall be effective upon electronic distribution, and shall be posted to the WECC website within one (1) business day of electronic distribution.~~

~~8.5.8 Quorum. No business shall be conducted by the MAC unless a majority of the MAC members is present, including at least one MAC member from each Member Class which elects MAC members (not including subclass designations).~~

~~8.5.9 Majority Vote. A decision of the MAC shall be upon a simple majority vote of committee members voting unless otherwise required in other bylaw provisions.~~

~~8.5.10 Remote Participation at MAC Meetings. Any or all of the MAC members may participate in any meeting of the MAC electronically or by telephone, or by any other means of communications which enables the MAC members to simultaneously hear one another. Every MAC member participating in a meeting in this manner will be deemed to be present in person at the meeting.~~

8.5.11 Reporting to the Board. The MAC Chair, or designee, shall provide a report to the Board at each Board meeting detailing the business carried out by the MAC, and advising the Board of MAC recommendations on matters as set forth in Section 8.2.1 herein. In the event that there are dissenting MAC member opinions regarding a matter on which the MAC is advising or providing recommendations to the Board, the MAC Chair, or designee, shall present dissenting opinions and rationales in conjunction with the respective MAC advice or recommendations.

8.5.12 Open Meetings. Except as provided in Section 8.5.13, all regular and special meetings of the MAC will be open to observation by any Member, Director, and/or any member of the public.

8.5.13 Closed Session. Notwithstanding the provisions of Section 8.5.12, after a quorum has been established at any MAC meeting and upon an affirmative vote of two-thirds (2/3) of the MAC members present, the MAC may close an open meeting and reconvene in closed session in the following instances: (1) to receive and/or discuss confidential attorney-client privileged information from WECC's counsel; or (2) to receive and discuss any other information which is privileged, confidential, proprietary, trade secret, or otherwise protected from public disclosure by law.

8.5.13.1 Attendance by an Affected MAC Member. Closed sessions of the MAC may not be attended by a MAC member under the following circumstances: (1) when the qualification or performance of the MAC member is being discussed; (2) when the MAC member is employed by an entity that is or is likely to become a party to the litigation or legal issue being discussed; or (3) when the MAC Chair determines that the MAC member would have a conflict of interest by becoming privy to the privileged or confidential information that is to be presented to or discussed by the MAC in closed session.

8.5.13.2 Attendance by Directors. Any member of the Board may attend a closed session of the MAC unless the topic considered by the MAC concerns the Director.

8.5.13.3 Announcement and Adjournment of Closed Session. Prior to adjourning to a closed session, the MAC Chair will announce the purpose of the closed session in a manner that provides the public an understanding of the general subject matter to be discussed, but which does not reveal privileged, confidential or otherwise sensitive personal information. The closed session then shall be limited in scope to the publicly stated purpose of the closed session. After the closed session has ended, the MAC Chair shall provide the public a general description of the business conducted during the closed session, without breaching the confidentiality of the information used in the session.

8.5.13.4 Confidentiality of Closed Session. All MAC members and any others present at a closed session shall maintain the confidentiality of the information, discussions, and decisions made in closed session. Unless otherwise required, all MAC members and closed session attendees shall execute an appropriate confidentiality agreement provided by WECC's General Counsel. The MAC Chair will appoint a secretary for the closed session to take minutes of the closed session, which shall be delivered to the WECC Corporate Secretary. Minutes of the closed session will be maintained confidential by the Corporate Secretary.

8.5.14 MAC Committees. The MAC may appoint such subcommittees and work groups as it deems necessary from time to time to carry out its business affairs. In appointing such subcommittees or work groups, the MAC will specify, in a charter, their purpose, membership, voting, notice and meeting procedures, and other such direction as the MAC deems appropriate. The MAC may appoint one or more MAC members or other persons to participate in MAC subcommittees or work groups as full voting members or as non-voting advisory members.

8.5.15 MAC meetings and activities will be self-funded by Members with respect to labor and travel expenses. However, WECC and WECC staff will provide facilitation and coordination support, including payment for the expenses of meeting facilities. A MAC member may seek reimbursement, from WECC, for reasonable and actual travel expenses arising from attendance at MAC meetings, consistent with WECC employee travel expense reimbursements, where such MAC member's travel expenses are not reimbursed by any Member or other source.

8.6 **Procedures for Committees other than the Member Advisory Committee.**

8.6.1 Reports to Board of Directors. Action by a committee will be in the form of a recommendation for Board action except in those instances in which the Board has, by resolution, specifically delegated to a committee the power to take action subject to an appeal to the Board by any Member. The recommendation of a committee must be forwarded to the Board for its action along with any minority or dissenting reports filed with the committee Chair or Vice-Chair.

8.6.2 Subcommittees, Task Forces and Ad Hoc Groups. Any Board or member committee may create such subcommittees, task forces or other ad hoc groups ("subcommittee") as it deems appropriate to carry out the committee's responsibilities consistent with these Bylaws and the direction of the Board. The composition, responsibilities and procedures of such groups shall be specified by the committee as appropriate; provided, however that: 1) the committee may only delegate to such subcommittee responsibilities that are within the scope of the committee's responsibilities pursuant to these Bylaws and direction of the Board; and 2) the subcommittee may only make recommendations to the committee. A committee may create a subcommittee without prior approval of the Board; provided, however, that the committee shall promptly inform the Board in writing

and at the next Board meeting regarding the creation of the subcommittee. The notification to the Board shall include a charter for the subcommittee that describes how members of the subcommittee will be selected, the duties of the subcommittee, and whether the committee has established a sunset date for review of (1) the need for the subcommittee and (2) the charter of the subcommittee.

8.6.3 Committee Officers. The Board will appoint the Chair and Vice-Chair of each committee. The Committee Chair or Vice-Chair will preside over all meetings of the committee and will report recommendations of the committee to the Board of Directors. The Chair and Vice-Chair will be responsible for informing the Board regarding minority opinions and other information required by the Board along with overall committee recommendations. Whenever the committee elects to form a subcommittee to represent regions or address specific tasks, the Chair (or in the absence of the Chair, the Vice-Chair) will have the power to appoint the members of such subcommittee from both members of the committees and non-members. Upon resignation of the Committee Chair, the Vice Chair shall serve as Chair until the Board appoints a replacement. Upon resignation of the Vice-Chair, the Chair may appoint a temporary Vice Chair to serve until the Board appoints a replacement. Upon resignation of both the Chair and Vice Chair, the Chair of the Board may appoint one or more temporary replacements to serve until the Board appoints permanent replacements.

8.6.4 Committee Membership. Except as provided in Sections 8.2.2 and 8.6.4.1, any Member of WECC may designate one representative as its committee member to any standing committee or other committee. The WECC Member will have one vote at any committee meeting through that committee member. Any number of other persons may attend a committee meeting, but such persons will have no right to vote without a prior designation of representation by a WECC Member..

8.6.4.1 Dual Representation for Functionally-Separated Members. A Member which has distinct and functionally-separated interests as both a transmission provider and a transmission customer may designate two representatives as committee members to any standing committee, one to represent each functionally separate interest. Each such committee member will have one vote. The privilege granted by this Section is subject to revocation by the Board on a case-by-case basis or generally whenever the Board finds, upon petition from any Member or its own motion, that such dual representation creates unfairness or imbalance within a committee.

8.6.5 Committee Voting and Classes.

8.6.5.1 Classes. For purposes of voting, committees, excluding the WECC Standards Committee and the Member Advisory Committee, will have three classes of membership:

8.6.5.1.1 Transmission Provider Members;

8.6.5.1.2 Transmission Customer Members; and

8.6.5.1.3 States and Provincial Members (Member Class 5).

8.6.5.2 Voting. Except as provided in Section 4.5.2, each committee member will have one vote. In order for a recommendation to be made to the Board, such recommendation must receive a simple majority vote of both: 1) committee members present and voting from the Transmission Provider Class; and 2) committee members present and voting from Transmission Customer Class. The Board will adopt voting and record-keeping procedures to ensure that committee voting is conducted consistent with these Bylaws. This requirement will also apply where decision making power has been delegated to a committee pursuant to Section 6.9.1.

8.6.5.2.1 State and Provincial Votes. The position of the state and provincial Class committee members must be recorded, but the failure of a proposed recommendation or decision to obtain a simple majority vote of the state and provincial committee members will not prevent the recommendation or decision from being posted for due process comment or sent to the Board of Directors.

8.6.6 Notice and Review of Committee Recommendations and Decisions (Due Process). Committee recommendations or decisions delegated to a committee pursuant to Section 6.9.1 will be subject to the due process provisions of this Section. Following a committee's development of a proposed recommendation or decision, the committee will post the proposed recommendation or decision on the WECC website for review and comment by other WECC Members, and other interested parties. The committee will provide all Members e-mail notification of the posting and will allow at least thirty (30) days for comment on the proposal. The committee will consider all such additional input before reaching its final recommendation or decision. If the committee's recommendation or decision changes significantly as a result of comment received, the committee will post the revised recommendation or decision on the website, provide e-mail notification to Members and provide no less than ten (10) days for additional comment before reaching its final recommendation or decision. Upon reaching its final recommendation or decision, the committee will forward it to the Board. Whenever it determines that a matter requires an urgent decision, the Board may shorten any time period set forth in this Section, provided that: 1) notice and opportunity for comment on recommendations or decisions will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for comment.

8.7 **Procedures for Developing and Voting on Reliability Standards.**

8.7.1 Rights and Obligations of WECC Members and Participating Stakeholders. All WECC Members and Participating stakeholders are entitled to participate in the development of and to vote on Reliability Standards, Regional Criteria or revisions, subject to any applicable obligations, limitations and conditions set forth in these Bylaws, and in accordance with the WECC Reliability Standards Development Procedures.

8.7.1.1 Participation. The right to participate in Reliability Standards and Regional Criteria development and voting includes the right to request the development or revision of a Reliability Standard, the right to receive notice of, attend and participate in related WECC discussions, the right to review information relevant to a Reliability Standard or revision, the right to provide written comments on a proposed Reliability Standard, Regional Criteria, or revision, the right to participate in voting on a Reliability Standard, Regional Criteria, or revision and the right to file an appeal requesting review of any decision on a Reliability Standard, Regional Criteria, or revision.

8.7.2 Voting. The procedures and conditions for voting by WECC Members and Participating Stakeholders are set forth in the Reliability Standards Development Procedures.

8.7.3 Board Authority to Address Regulatory Directives. The Board shall have backstop authority to address regulatory directives as described in the Reliability Standards Development Procedures.

8.7.4 Participating Stakeholder Application Process. Any person or entity that is an interested stakeholder may apply to WECC for Participating Stakeholder status and, upon WECC's acceptance of such application, acquire the participation and voting rights set forth above in Section 8.7.1. WECC staff, under the direction of the CEO, will process applications and make the initial determination of eligibility for Participating Stakeholder status. Denial of Participating Stakeholder status may be appealed to the WECC Governance Committee and, if denied by the Governance Committee, to the WECC Board. A person or entity's Participating Stakeholder status will be maintained so long as the Participating Stakeholder continues to meet the requirements set forth in Section 3.24 and participates in at least one WECC meeting per year at which a Reliability Standard or revision is discussed. In the event a person or entity's Participating Stakeholder status lapses due to failure to meet the above minimum participation requirement, the person or entity may restore Participating Stakeholder status by re-applying for Participating Stakeholder status and attending a WECC meeting at which a Reliability Standard is discussed.

8.7.5 WECC Standards Voting Sectors. WECC staff shall confirm eligibility for the WECC Standards Voting Sectors set forth in the Reliability Standards Development Procedures. Decisions of the staff to approve, deny, or restrict the admission of an entity to a voting sector may be appealed to the Governance Committee. Decisions of the Governance Committee to affirm or reverse such decisions of staff may be appealed to the Board.

8.7.6 WECC staff shall require Ballot Body members to identify their affiliations with other Ballot Body members. Affiliates within a single Standards Voting Sector may only have one vote in that Standards Voting Sector. Affiliates within a single Standards Voting Sector must designate a single Affiliate as the group's Ballot Pool member to vote in that Standards Voting Sector.

8.8 **Notice of Committee Meetings.**

8.8.1 Standing Committees. The committee Chair, with the assistance of the Chief Executive Officer, will ensure that not less than ten (10) days' notice of all standing committee meetings is posted on the WECC website and is also provided to: 1) members of the committee; 2) Participating Stakeholders (if the meeting concerns development or approval of a Reliability Standard or revision); and 3) any WECC Member or member of the public requesting notice. A committee may take up any matter at a duly noticed meeting including matters not expressly identified in the notice; provided, however, that a final recommendation to the Board must be made in accordance with Section 8.6.1.

8.8.2 Other Committees. Notice of other committee meetings will be provided in the manner adopted for such notice by the affected Members and in accordance with the requirements of Section 8.8.1.

8.98.4 **Open Meetings.**

All committee meetings of WECC will be open to any WECC Member, Director and for observation by any member of the public, except as set forth in these Bbylaws or in Board-approved policies or committee charters describing the criteria for entering intoon closed sessions applicable to the committee in questionthat the Board may adopt for the purpose of preventing public disclosure of information that the Board might more appropriately discussed in closed session.

9. The Chief Executive Officer, Officers, and Employees.

9.1 **Designation of Officers and Terms of Office.**

WECC will have a Chief Executive Officer, a Secretary, and any other officers specified by the Board from time to time. The Chief Executive Officer will also hold the title of President of WECC if applicable law requires WECC to have a President. Each officer will be appointed by the Board and will serve for the term of office specified in the Board action appointing the officer and until a his or her successor is appointed. If an officer is also an employee of WECC, the officer's appointment will automatically end upon termination of

such employment. Any two or more offices may be held by the same person except the offices of Chief Executive Officer and Secretary.

~~9.2 **Chief Executive Officer Qualifications.**~~
~~The Chief Executive Officer will be a person with senior management level experience and knowledge of bulk power electric transmission systems reliability, planning and operations.~~

~~9.3~~9.2 **Standards Applicable to All Employees.**
A person may not be an officer or employee of WECC if:

1) the person is also the employee of or has a contractual relationship with any Entity, or any Affiliate of any Entity, that is eligible for membership in WECC; or
2) the person has a financial interest that, in the judgment of the Board or the Chief Executive Officer, creates the fact or appearance of bias, undue influence or lack of objectivity regarding any action or decision of WECC.

The ~~Board will adopt~~Officers and Employees Standards of Conduct ~~for officers and employees~~ attached hereto as Appendix B set~~ting~~ forth the~~ir~~ duty of care, duty of loyalty, duty to avoid conflicts of interest and related matters intended to promote officer and employee~~their~~ neutrality, objectivity and professionalism. ~~Upon adoption, such standards shall be attached hereto as Appendix B.~~

~~9.3.1~~9.2.1 Exemptions ~~from the disqualification criteria found in Section 9.3 are as follows~~:

~~9.3.1.1~~9.2.1.1 Status as a residential electricity customer will not disqualify a person from employment with WECC.

~~9.3.1.2~~9.2.1.2 A candidate for ~~Chief Executive Officer or employee~~employment ~~of WECC~~ will not be disqualified for owning shares in a mutual fund ~~because the mutual fund~~that owns an interest in a Member or an Affiliate ~~of a Member~~.

~~9.3.1.3~~9.2.1.3 ~~The disqualification standards described in Section 9.3 will not apply to disqualify a~~A candidate for employment will not be disqualified for ~~who is~~ receiving payments from a pension plan of a Member or an Affiliate ~~of a Member~~ in a form other than securities of such Member or Affiliate if the pension plan payments bear no relationship to the economic performance of the Member or Affiliate.

~~9.3.2~~9.2.2 If an officer or employee ~~receives a gift or inheritance~~comes into possession of securities in any Member or Affiliate, ~~he/she~~the officer or employee must resign or dispose of such securities within six (6) months of the date of receipt. ~~–~~ Within six (6) months of the time a new Member is added in which an officer or employee owns securities, the officer or employee will resign or dispose of those securities.

~~9.4~~9.3 **Employment.**

The Chief Executive Officer will be employed by the Board of Directors and will serve at the Board's pleasure. Any contract of employment with a Chief Executive Officer will permit the Board to dismiss the officer with or without cause.

~~9.5~~9.4 **Chief Executive Officer's Duties.**

Subject to the Board's direction and delegation, the Chief Executive Officer shall have the authority necessary to plan, organize, staff, and manage WECC to achieve its mission and to perform the activities specified in Section 2 of these Bylaws. Subject to limitation by the Board, the CEO may delegate these authorities in whole or in part to other WECC employees.~~or his/her designees will have the following duties, among others:~~

~~9.5.1 Execute policies at the direction of the Board and be responsible to the Board for the performance of the WECC functions described in Section 2;~~

~~9.5.2 Hire and fire staff within the constraints of the annual budget;~~

~~9.5.3 Perform administrative duties, such as preparing annual budgets for the approval of the Board, making employment decisions and ensuring conformance with regulatory requirements;~~

~~9.5.4 Develop and implement employment policies and standards of conduct; and~~

~~9.5.5 Accept or reject membership applications in accordance with the criteria of these Bylaws.~~

~~9.6~~9.5 **Secretary's Duties.**

In addition to any delegation from the Board, the Secretary shall have the authority and responsibilities specified in applicable Utah law pertaining to nonprofit corporations.

~~9.6.1 Maintain Member and Affiliates Lists. The Secretary will maintain continuously updated lists of all Members and Affiliates.~~

~~9.6.2 Maintain Official Records. The Secretary will keep minutes of all WECC Board and Member meetings and will receive and maintain minutes of committee meetings and all other official records of WECC. Within five (5) business days after any vote taken by Members, the Board, a Class or any committee, the Secretary will provide notice to all Members and Participating Stakeholders (if applicable) of the results of such a vote through postings on the website, email and/or other means of communication.~~

~~9.6.3 Maintain Website. The Secretary will oversee the creation, maintenance, and updating of the WECC's website and the information published through it.~~

10. Dispute Resolution.

The Board may adopt reasonable dispute resolution procedures applicable to WECC members and staff~~Except as may be otherwise provided herein, and subject to the conditions set forth in Appendix C, Section A.1, disputes between Members and/or WECC will be resolved pursuant to the WECC Dispute Resolution Procedures set forth in Appendix C. Matters subject to the jurisdiction of the WECC Compliance Hearing Body are not subject to the procedures in Appendix C~~.

11. Costs and Finances.

11.1 Funding of Reliability Activities.

11.1.1 U.S. Statutory Funding.~~—~~ WECC shall fund all activities undertaken pursuant to Section 215 of the Federal Power Act in accordance with the funding provisions and procedures of that law and related FERC regulations and orders.~~—~~ The Board shall approve a budget for such activities in time for submission to the ERO and to ~~the~~ FERC for approval of such funding in accordance with applicable requirements.

11.1.2 International Funding. WECC shall fund reliability activities undertaken in accordance with any agreements it enters into with Canadian or Mexican Entities.~~-~~ Specifically:

~~(a~~1) Subject to (b), ~~in the event that~~if a Canadian or Mexican Entity seeks membership in ~~the~~ WECC, that Entity may elect to negotiate an agreement with WECC that provides the terms upon which that Entity will become a Member and, among other things, participate in and/or fund WECC.~~—~~ In such a case and unless agreed otherwise, the Canadian or Mexican Entity shall not be a Member of WECC and shall not have an obligation to fund activities undertaken by the WECC until the terms of such agreement are executed.

~~(b~~2) Section 11.1.2(a) shall not apply to any Canadian or Mexican Entity that is a Member as of the date of the approval of these WECC Bylaws.~~—~~ Existing Canadian or Mexican Members shall continue as Members in accordance with the terms and conditions of their membership as of the date of the approval of the WECC Bylaws, including the terms and conditions of any agreements in place as of the date of the approval of these WECC Bylaws.~~-~~ Nothing in the Section precludes existing Canadian or Mexican Members from negotiating an agreement with WECC that modifies the terms of ~~its~~ their participation in and funding of WECC at any time.

11.1.3 Equitable Allocation of Funding.~~-~~ In adopting budgets for the costs of reliability activities, the Board shall endeavor to achieve an equitable allocation as between funding through Sections 11.1.1 and 11.1.2 based ~~up~~on the net energy to load and other relevant factors consistent with applicable law, the Delegation Agreement and

any ~~International Reliability Agreements~~applicable agreements with Canadian or Mexican authorities.

11.2 **Dues.**

The Board may require Members ~~and Participating Stakeholders~~ to pay nominal annual dues consistent with applicable FERC requirements (or those ~~of International Reliability Agreements as applicable~~ contained in applicable agreements with Canadian or Mexican authorities) to cover reasonable costs of membership ~~and/or participation in standards development~~ that are not funded through Sections 11.1.1 or 11.1.2. ~~—~~ Initial dues of a Member ~~or Participating Stakeholder~~ will be submitted with a completed application for membership ~~or Participating Stakeholder status~~ and will be ~~for the~~ prorated ~~share of the full annual amount~~ based on the Member's ~~or Participating Stakeholder's~~ actual months of membership ~~or participation~~ in the calendar year. ~~–~~ In determining nominal dues, the Board may consider all relevant factors including, but not limited to, the ability of different classes of membership ~~or Participating Stakeholders~~ to pay such dues. ~~—~~ The Board may also reduce, defer or eliminate the dues obligation of an individual Member ~~or Participating Stakeholder~~ for good cause shown.

11.3 **Funding of Non-Statutory Activities**.

To the extent that WECC elects to fund any activities not eligible for funding pursuant to Sections 11.1.1 and 11.1.2, it shall do so through the use of service fees, charges or dues applicable to the persons or entities that voluntarily participate in such activities. Participation in or funding of such activities shall not be a condition of membership in WECC.

12. Amendments to these Bylaws.

These Bylaws may be amended by either the Board or by the Members in accordance with the following procedures.

12.1 **Amendment by the Board.**

Except for those provisions described below, the Board may approve an amendment of the Bylaws after providing not less than thirty (30) days' notice of the proposed amendment to all Members. ~~–~~Approval of such an amendment requires the affirmative votes of not less than two-thirds (⅔~~2/3~~) of the Directors in office. Such amendment will become effective sixty (60) days after its approval by the Board ~~(1)~~ unless:

1) the vote is appealed ~~to~~ by the Members prior to the sixtieth day, or

2) subsequent regulatory approval is required.

~~A Member~~To lodge an appeal, ~~shall be sufficient to hold implementation of an amendment if~~ a majority of any Class may file~~s~~ a petition with the Secretary ~~seeking appeal of such amendment~~. ~~–~~ An appeal will stay implementation of the amendment pending Member vote on the appeal. ~~If such an appeal is received,~~ T~~t~~he membership will vote on whether to rescind the Board approved amendment at the next Annual Member Meeting unless the Board calls an earlier S~~s~~pecial Member M~~m~~eeting ~~of the Members beforehand~~. ~~–~~ An appeal will only be successful if a majority of all Members and a majority (three of five) of ~~Member~~

the Classes vote to rescind the amendment. If the appeal vote is not successful, then the amendment will be deemed approved as of the day of the failed Membership vote. If subsequent regulatory approval is required for the amendment, then the amendment shall be effective upon the effective date of such approval.

12.1.1 Notwithstanding the foregoing, both Board and Member approvals ~~is~~ are required to amend provisions of these Bylaws concerning Sections 1.1 and 1.2; Section 4.2; Sections 6.2 through 6.8, inclusive; Section 7.2; Section 8; Section 10; Sections 12.1 through 12.4, inclusive; ~~Appendix C,~~ and any other sections as may be required by Utah law. In such case, the Board shall first vote on the proposed amendment. If approved by the Board ~~by the majority specified in Section 12.1 necessary to attain Board approval~~, the amendment must then be noticed to Members at least sixty (60) days prior to the Annual Member Meeting or ~~a~~ Special Member Meeting at which the Member vote will occur. The amendment will then be approved if it receives the affirmative vote of at least~~approved by~~ two thirds (⅔~~2/3~~) ~~or more~~ of the Members who vote upon such amendment.

12.2 **Amendment by the Members.**
Upon a petition being filed with the Secretary by any Member or Director, at any Annual Member Meeting or Special Member Meeting the Members may amend any provision of these Bylaws; provided:

1) the proposed amendment has first been presented to the Board and not adopted ~~(this provision will not apply to amendments which the Board is prohibited from adopting)~~;

2) Members have received not less than sixty (60) days' notice of the proposed amendment, the reasons there for and a statement of the Board's position regarding it; and

3) the amendment receives the affirmative votes of not less than two-thirds (⅔~~2/3~~) of all Members and a majority of ~~Member~~ the Classes.

~~12.3 **Amendments in Response to Mandatory Membership.**~~
~~If at any time, pursuant to legislation or otherwise, membership becomes mandatory for some or all Members, upon the request of the affected Member(s) the Board will consider amendments to these Bylaws appropriate to such mandatory membership.~~

~~12.4~~12.3 **Amendments proposed by FERC.**
FERC, upon its own motion or upon complaint, may propose an amendment to these Bylaws pursuant to 18 C.F.R. § 39.10(b).

12.4 **Remote Member Voting on Amendments Permitted.**
In all cases where a Member vote is required for approval of a proposed Bylaws amendment pursuant to section 12.1.1, that vote may occur in conjunction with an Annual or Special Member Meeting as described in section 12.1.1, or voting may occur in whole or in part through submission of written or electronic ballots in accordance with procedures determined by the Secretary to ensure the integrity of the voting process,

provided that in such cases the proposed amendment has been noticed to Members at least thirty (30) days prior to the beginning of balloting.

13. Termination of Organization.

WECC may be terminated ~~up~~on a vote of a majority of the Members in accordance with the provisions of Utah law, the Federal Power Act ~~and~~ the ~~requirements of the~~ Delegation Agreement and applicable agreements with Canadian or Mexican authorities~~International Reliability Agreements~~. Immediately upon such a vote, the Board will, after paying all debts of WECC, distribute any remaining assets in accordance with the requirements of Utah law, the Internal Revenue Code and these Bylaws.

14. Miscellaneous Provisions.

14.1 **Limitation on Liability.**

It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in Section 4.8 hereof shall be the sole and exclusive remedies available hereunder for any nonperformance of obligations under these Bylaws. Subject to any applicable state or federal law ~~which~~ that may specifically limit a Member's ability to limit its liability, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members or to third parties for any loss or damage to property, loss of earnings or revenues, personal injury, or any other direct, indirect, or consequential damages or injury ~~which~~ that may occur or result from the performance or nonperformance of these Bylaws, including any negligence, gross negligence, or willful misconduct arising hereunder. This Section 14.1 of these Bylaws applies to such liability as might arise between Members under these Bylaws. This Section 14.1 does not apply to parties to the Agreement Limiting Liability Among Western Interconnected Systems ("WIS Agreement") with respect to matters covered by the WIS Agreement and does not apply to any liability provision in any other agreement.

14.2 **Indemnification.**

WECC shall indemnify and hold harmless its Directors, officers, employees, agents and advisors against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements), resulting from or relating to, in any way, any claim, action, proceeding or investigation, instituted or threatened, arising out of or in any way relating to any action taken or omitted to have been taken (or alleged to have been taken or omitted to have been taken) by such person in connection with actions on behalf of WECC, and against any and all damages, losses, fines, costs and expenses (including attorneys' fees and disbursements) incurred in connection with any settlement of any such claim, action, proceeding or investigation unless such action of such person is determined to constitute fraud, gross negligence, bad faith or willful misconduct with respect to the matter or matters as to which indemnity is sought.

14.3 **No Third-Party Beneficiaries.**

Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to or any liability to any third party.

14.4 **Informal Inquiries for Information.**
Nothing in these Bylaws shall preclude:

1) a Member from making an informal inquiry for information outside of the procedures outlined in Section 4.6.11 hereof to another Member and

2) that other Member from responding voluntarily to that informal inquiry, provided, however, that any such response to an informal inquiry for information shall not be binding upon that other Member and shall be used by the Member making the informal inquiry for informational purposes only.

15. Incorporation.

WECC shall organize itself as a non-profit corporation pursuant to the laws of the state of Utah regarding non-profit corporations under the name "Western Electricity Coordinating Council." All Members agree to take no actions that would contravene the ability of WECC to maintain its status as a non-profit corporation existing pursuant to the Utah Act.– The Board shall adopt these Bylaws as the Bylaws of WECC as a non-profit corporation.

WECC is intended to qualify as an organization described in Section 501(c)(4) of the Internal Revenue Code.– No part of any net earnings of WECC shall inure to the benefit of any Member or individual.– Upon liquidation, to the extent consistent with the Internal Revenue Code and Utah law, any monies remaining from assessments paid by Members for the costs of WECC shall be rebated to Members in proportion to their payments.– Any remaining assets of WECC shall be transferred to another organization exempt from tax under Section 501(a) of the Internal Revenue Code, or government agency, promoting the same purposes as WECC, as designated by the Board.

16. Governing Law.

Unless otherwise agreed, if any conflict of law arises under these Bylaws among the Members, the laws of the United States of America shall govern, as applicable.- The venue for any legal action initiated under these Bylaws shall be the city and state (or province) in which the headquarters of WECC is located.

~~17. WECC Transition~~

~~The provisions of this Section shall apply to that period of time and activities associated with the transition of WECC from a hybrid Board of Directors to an independent Board of Directors with a Member Advisory Committee.~~

~~17.1 Board of Directors transition.~~

~~17.1.1 The transition of WECC governance from a hybrid Board to an independent Board of Directors will be effective upon the effective date of Federal Energy Regulatory Commission approval of Section 6.1 establishing an independent Board ("Effective Date"). The non-affiliated directors of WECC, whose terms extend past the Effective Date, so willing to continue to serve, shall form part of the initial cadre of independent Directors. These continuing Directors shall be entitled to serve the remainder of their respective three-year terms of office.~~

~~17.2 Transition Exceptions~~

~~The nomination, election and term of additional independent Directors shall be in conformance with the requirements of these bylaws, as amended, except:~~

~~17.2.1 The requirement that the Nominating Committee notify the Board Chair of the committee's nominations sixty (60) days prior to an Annual Meeting shall not apply.~~

~~17.2.2 Appointments of Member Advisory Committee members to the Nominating Committee shall be made such that no one class can occupy more than one seat at a time and cannot have a representative on the committee more than two years in a row.~~

~~17.2.3 Director positions of non-affiliated directors of WECC, whose terms extend beyond the Effective Date, but whose directors resign or indicate they will resign prior to the Effective Date, will be filled through the same nomination and election process used to select additional independent directors as provided above.~~

~~17.2.4 Those Directors first elected as a result of this transition from a hybrid to an independent Board will draw lots to determine their term length determined to achieve the staggered terms required by Section 6.3.~~

~~17.2.5 The nomination and election of a number of additional Directors needed to seat the entire Independent Board as described in section 6.4 as of the Effective Date may occur prior to the Effective Date. While the nomination and election of an individual to a director position may occur prior to the Effective Date, such nomination and election shall have the full force and effect of these bylaws after the Effective Date.~~

~~17.3 Member Advisory Committee transition~~

~~17.3.1 Initial Formation. When there is a meeting where Members vote to amend the WECC bylaws to provide for a Member Advisory Committee (MAC), the MAC will initially be constituted through elections conducted in conjunction with the same meeting.~~

~~17.3.2 Election of the initial MAC member representatives shall be as provided in these bylaws, as amended, except:~~

~~17.3.3 Where what had been the Class Seven membership category is combined with the Class Three membership category, Class Seven Members will indicate, prior to the meeting, whether they intend to continue participation in WECC as a member of the newly combined Class Three category. Entities so indicating will be considered members of Class Three for purposes of the initial formation of the MAC and shall~~

~~be entitled to participate in elections for Class Three member representatives of the MAC.~~

~~17.3.4 Member Classes will not be allowed to subdivide into subclasses for purposes of electing class representative MAC members at the meeting where the MAC is initially formed and where initial MAC member elections are conducted.~~

~~17.3.5 The terms of each Class' three (3) initial Class representative members on the MAC shall be allocated, by the drawing of lots, such that the intended staggered terms for MAC members will be obtained, with one of a Class' initial MAC member representatives serving an initial term of one year, another two years, and another three years.~~

APPENDICES

A. Board Member Standards of Conduct

B. Officers and Employees Standards of Conduct

~~C. WECC Dispute Resolution Procedures~~

Appendix A
Standards of Conduct for
Members of the WECC Board of Directors

By accepting appointment to the Board of Directors (the "Board") of the Western Electricity Coordinating Council ("WECC"), a Director agrees to abide by the duties required of corporate directors and trustees. Utah law (and similar law in other states) imposes quasi-fiduciary duties of care and loyalty on all corporate directors or trustees, including directors and trustees of nonprofit corporations. For as long as ~~he or she~~the Director remains a member of the Board of Directors of WECC, ~~a~~the Director will abide by the following standards of conduct.

I. Duty of care. The Directors of a corporation are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation. This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

A. Each Director will regularly attend Board of Directors meetings, digest the materials sent ~~to him or her~~, participate in Board discussions and make independent inquiries as needed.

B. In voting on any matter before the Board or otherwise acting in ~~his or her~~the capacity as a Director, each Director will:

1. make reasonable inquiry to be informed ~~himself or herself~~ of the nature and consequences of the matter or action at issue;

2. exercise, at a minimum, the degree of care, skill, and diligence that an ordinarily prudent business person would exercise under similar circumstances; and

3. act in a manner ~~the Director~~, ~~in the exercise of his or her~~the Director ~~independent judgment,~~ believes to be in the best interests of WECC and the membership of WECC, taken as a whole.

C. In exercising the duty of care described in paragraphs IA and B above, a Director has the right to rely on statements by the persons immediately in charge of business areas of WECC, to rely on professionals and experts (such as engineers, accountants and lawyers) and to rely on committees of WECC, unless facts or circumstances appear which would prompt further concerns of the ordinarily prudent person.

II. Duty of loyalty. The duty of loyalty imposes on a Director the obligation to remain loyal to WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain. This duty does not preclude a Director from being employed in a competing or related business so long as the Director acts in good faith and does not interfere with the business of WECC.

A. Each Director will carry out ~~his or her~~the duties ~~as~~ of a Director in good faith.

B. Each Director will refrain from using any influence, access, or information gained through ~~his or her~~ service as a Director to confer any improper personal benefit (financial or otherwise) upon ~~himself or herself~~the Director, any family member, or any person living in the Director's household.

C. Each Director will refrain from using any influence, access, or information gained through ~~his or her~~ service as a Director to confer an improper benefit (financial or otherwise) on any organization:

1. for which the Director serves as an officer, director, employee, consultant, or in any other compensated or management position; or

2. in which the Director or any family member or person living in the Director's household has a material financial interest (whether as a shareholder, partner, or otherwise).

D. To the extent permitted by law, each Director will maintain the confidentiality of:

1. any confidential or proprietary information of WECC disclosed or available to the Director;

2. any confidential or proprietary information of WECC Member(s) to which the Director has access by virtue of ~~his or her~~the status as Director; and

3. any confidential or proprietary information of third parties that has been provided to WECC or the Board on condition of confidentiality.

E. Conflicts of Interest.~~—~~ Because conflicts of interest may arise ~~from time to time~~, specific guidelines are provided.~~—~~ In general, conflicts of interest involving a Director are not inherently illegal nor are they to be regarded as a reflection on the integrity of the Board or of the Director.~~–~~ It is the manner in which the Director and the Board deal with a disclosed conflict that determines the propriety of the transaction.

Directors of nonprofit corporations may have interests in conflict with those of the corporation.~~–~~ The duty of loyalty requires that a Director be conscious of the potential for such conflicts and act with candor and care in dealing with these situations.

The following are guidelines for Directors with actual or potential conflicts of interest:

1. Each Director has a responsibility to recognize potential conflicts of interest and to be guided when acting as a Director by his or her independent judgment of what is in the best interests of WECC and the membership of WECC, taken as a whole.~~–~~ If any Director has questions about whether a conflict of interest exists, he or she may make inquiry to the Chief Executive Officer of WECC for advice.

2. Potential conflicts of interest may arise because of a Director's private, individual interests (personal conflicts of interest) or because of relationships the Director may have with other organizations or interest groups (organizational conflicts of interest). Current or past employment or other compensation-based relationships with one or more WECC Members are examples of potential organizational conflicts of interest. Whether a potential conflict of interest is personal or organizational, in all cases involving WECC affairs a Director's conflicting interests are subordinate to those of WECC and the membership of WECC, taken as a whole.

3. Personal conflicts of interest.

   a. Personal conflicts of interest exist if a Director, a member of the Director's family, or a person sharing the Director's household:

      1) has a material financial interest in a matter or transaction that comes before the Board for action; or

      2) stands to receive a benefit (in money, property, or services) from a transaction involving WECC to which the person is not legally entitled.

   b. In cases of personal conflicts of interest, the affected Director's obligations are to:

      1) disclose to the Board, before the Board acts with respect to that matter, the material facts concerning the Director's personal conflict of interest; and

      2) refrain from voting, and from attempting to influence the vote of any other Director(s), in those matters in which the Director has a personal conflict of interest.

4. Organizational conflicts of interest.

   a. An organization has a "direct" conflict of interest if a decision by the Board would confer material benefits on that organization that other WECC Members would not share, or impose material detriments or costs on that organization that other WECC Members would not share.~~—~~ The fact that many if not all Members are affected to some extent by Board decisions on core issues such as standards, new transmission lines and their ratings, does not create or constitute a "direct" conflict of interest.

   b. It is not a "direct" conflict of interest for a Director to be associated with an organization or an interest group that may stand to benefit from decisions made or actions taken by the Board, so long as the Director does not attempt to use ~~his or her~~the position ~~as a~~of Director to confer special

benefits on associated organizations or interest groups when other WECC Members would not share in those benefits.

c. In cases of potential "direct" organizational conflicts of interest, the affected Director's obligations are to:

1) disclose to the Board, before the Board acts with respect to the matter, the material facts concerning the organizational conflict of interest; and

2) refrain from voting and from attempting to influence the vote of any other Director(s) with respect to the proposed action or decision.

Appendix B
Officers and Employee
Standards of Conduct

By accepting employment with the Western Electricity Coordinating Council ("WECC"), an Employee agrees to abide by these Standards of Conduct. For the purpose of these Standards, an Employee includes each and all officers, employees and substantially full-time consultants and contractors of WECC.

I. Duty of care.– The Employees of WECC are bound to use due care and to be diligent in respect to the management and administration of the affairs of the corporation.– This duty of care is generally thought to have two components: the time and attention devoted to corporate affairs and the skill and judgment reflected in business decisions.

Employees shall not have any outside employment that limits in any way their ability to fulfill their employment responsibilities to WECC.– If an Employee has any question about whether outside employment is consistent with this standard, they should consult with their supervisor.

II. Duty of loyalty.– The duty of loyalty imposes on an Employee the obligation to remain loyal to the WECC, acting at all times in the best interests of WECC and its Members as a whole and unhampered by any personal pecuniary gain.– WECC expects all Employees to avoid adversely affecting the public's confidence in the integrity and reputation of WECC.– Any conduct or activities of any Employee should be capable of being justified and withstanding public scrutiny.

A. Each Employee will carry out his or her duties as an Employee in good faith, with integrity and in a manner consistent with these Standards and all applicable laws governing WECC.

B. Each Employee will refrain from using, or creating the appearance of using, any influence, access, or information gained through his or her service as an Employee to confer any improper personal benefit (financial or otherwise) upon himself or herself, or Family Member.[1] Employees shall not accept gifts or entertainment that would tend to affect, or give the appearance of affecting, the performance of their duties; provided, however, that Employees may accept de minimus food or entertainment or non-cash gifts received as part of a social or special occasion in amounts not to exceed $~~1000~~ 25 per source per ~~year~~event.

C. Each Employee will refrain from using, or creating the appearance of using, any influence, access, funds or information gained through his or her service as an Employee to confer an improper benefit (financial or otherwise) on any organization.– The obligation to avoid the appearance of impropriety shall apply in particular to any organization:

1– For purposes of these Standards, a Family Member includes a spouse, domestic partner, child of the Employee, or a– relative living in the same home as the Employee.

1. for which the Employee is serving or has in the past served as an officer, director, employee, consultant, or in any other compensated or management position; or

2. in which the Employee, or Family Member has a material financial interest known to the Employee (whether as a shareholder, partner, or otherwise).

D. Employees shall not use their WECC position, WECC funds or WECC resources to support any political party, candidate or proposition except as expressly authorized by the Board.

E. To the extent permitted by law, each Employee shall maintain the confidentiality of:

1. any confidential or proprietary information of WECC disclosed or available to the Employee;

2. any confidential or proprietary information of WECC Member(s) to which the Employee has access by virtue of his or her status as Employee; and

3. any confidential or proprietary information of third parties that has been provided to WECC or the Board on condition of confidentiality.

F. Conflicts of Interest.– The following conflicts of interest policy shall apply to all WECC Employees.– Conflicts of interest may arise from time to time. In general, conflicts of interest involving an Employee are not inherently illegal, nor are they to be regarded as a reflection on the integrity of WECC or of the Employee.– It is the manner in which the Employee and WECC deal with a disclosed conflict that determines the propriety of the transaction. The following are guidelines for Employees with actual or potential conflicts of interest:

1. In general, personal conflicts of interest exist if an Employee, or a Family Member, has a material financial interest in a matter or transaction that comes before WECC for action, or stands to receive a benefit (in money, property, or services) from a transaction involving WECC to which the person is not legally entitled.– For purposes of determining whether stock constitutes a material financial interest, see Paragraph F(6) below.

2. Organizational conflicts of interest exist if an Employee, or a Family Member, has a relationship with an organization or interest group that would cause a reasonable person to believe such Employee's judgment, loyalty, or objectivity might be influenced in a way that is adverse to the interests of WECC.

3. Where there is any question about potential conflicts of interest, the Employee shall disclose to the Chief Executive Officer as soon as possible and prior to when WECC takes action with respect to that matter, the material facts concerning the Employee's personal conflict of interest, and refrain from participating in, or from

attempting to influence the action of any Directors or Employee(s) of WECC regarding those matters in which the Employee has a conflict of interest.

4. No Employee may be an employee, director of, or consultant to or provide services to or be associated in any way with any WECC Member without full disclosure to, and written consent of, the Chief Executive Officer.– To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(4), the Employee shall promptly notify the Chief Executive Officer, who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

5. No Employee shall participate in any electric energy transaction other than for ordinary personal use except to the extent necessary to, and consistent with, the functions of WECC.– Participation in an energy transaction includes, but is not limited to, purchasing, selling, marketing, or brokering of electricity, ancillary services, electricity transmission or electricity distribution.– To the extent that an Employee becomes aware that a Family Member is or will in the future be engaged in activity described in this Paragraph F(5), the Employee shall promptly notify the Chief Executive Officer who shall review all the material facts and determine whether they constitute a conflict of interest pursuant to Paragraphs F(1) and F(2), above.

6. All Employees shall promptly disclose to the CEO and the Chair of the Board any direct or indirect financial interest in excess of $5,000 (including the direct or indirect ownership of securities) held by the Employee or a Family Member living with the Employee[2] in any Electric Line of Business entity as defined in Section 3.15 of the Bylaws doing business in the Western Interconnection.– Upon such disclosure, the CEO and the Chair of the Board shall determine whether such financial interest constitutes a conflict of interest, or the appearance thereof, in light of the duties of the Employee, the ability to divest such financial interest without undue hardship and the totality of the circumstances.– In response to such disclosure, the CEO and the Board ~~C~~chair may impose such remedies as are reasonable under the circumstances and consistent with section 9.3 of the Bylaws. Such remedies may include, but are not limited to, restrictions on the Employee's duties or involvement in certain matters, transfer of the Employee to another position, broader disclosure of the financial interest, voluntary or mandatory divestiture of the interest (in whole or in part) or other remedies. Pursuant to section 9.3.2 of the Bylaws, if an Employee (not a Family Member) receives a gift or inheritance of securities of a Member of WECC, or if a new Member joins

2 Nothing in this section shall require an Employee to investigate the financial interests of Family Members not living with the Employee.– However, to the extent known to the Employee, the financial interests of a Family Member not living with the Employee may create a potential conflict of interest (or appearance thereof) subject to Sections II(B) and/or II(F)(1) of these standards, in which case disclosure pursuant to Section II(F)(3) is appropriate.

WECC in which the Employee (not a Family Member) holds securities, the Employee must resign or divest such securities within six months thereafter. For the purposes of this section, none of the following shall constitute a direct or indirect financial interest:

a. An interest that exists through diversified mutual funds;

b. An interest that exists for six months following receipt of a gift or inheritance of securities of a Market Participant or acceptance of employment with WECC, whichever is later ~~(provided that employees of the WSCC shall have two years from WECC organizational meeting to divest securities in their possession as of that date)~~;

c. An interest that exists through a pre-existing participation in a qualified defined benefits pension plan or health benefits plan of a Market Participant so long as the benefits under such plan do not vary with the economic performance or value of the securities of such Market Participant.

Appendix C

WECC Dispute Resolution Procedures

C. DISPUTE RESOLUTION.

C.1 Obligation To Comply with Dispute Resolution Procedures. If any dispute concerning one or more issues identified in Section C.2 below arises between a Member and one or more other Members, or between one or more Members and WECC, all of the parties to the dispute shall, to the extent permitted by law, be obligated to comply with the dispute resolution procedures specified in these Bylaws (except to the extent all of the parties to the dispute may agree otherwise as provided in Section C.4 below). Only Members and WECC have the right to invoke the provisions of this Appendix C and, except where all affected parties have separately agreed otherwise with respect to a particular dispute, only Members and WECC are obligated to carry out the dispute resolution procedures set forth herein. Any dispute subject to the provisions of this Appendix C to which WECC is made a party shall be subject to the additional requirements specified in Section C.3 below if the dispute is initiated by a party other than WECC. To the extent permitted by law (and except as otherwise permitted by the provisions of Section C.6.3), no party to a dispute subject to the provisions of this Appendix C may pursue any other available remedy with respect to the dispute until all of the parties to the dispute have fully complied with the dispute resolution procedures specified herein, *provided, however*, that if any party to a dispute subject to the provisions of this Appendix C refuses to comply with the dispute resolution procedures specified herein, all other parties to the dispute shall subsequently be relieved of any further obligation to comply with these dispute resolution procedures before pursuing other remedies in connection with that dispute.

C.2 Issues Subject to Dispute Resolution Procedures. Any dispute between or among the parties identified in Section C.1 above (that the parties to the dispute do not resolve through negotiations between or among themselves) shall be subject to the dispute resolution procedures set forth in this Appendix C if the dispute concerns: (i) the application, implementation, interpretation, or fulfillment of any guidelines, criteria, policies, procedures, or Bylaws of WECC or the North American Electric Reliability Council (or any successor organization); or (ii) any matter specified in Section C.6.2 below; except that any matter that is subject to the jurisdiction of the WECC Compliance Hearing Body is not subject to the requirements of this Appendix C. Notwithstanding the foregoing provisions of this Section C.2, however, neither WECC nor any Member shall be obligated to comply with the dispute resolution procedures of these Bylaws if: (a) the dispute is between two or more Members (or WECC), all of which, at the time of the dispute, are parties to the WECC Reliability Management System Agreement and the matter is within the scope of the dispute resolution procedures set forth in that agreement; or (b) the dispute is between two or more Members, all of which, at the time of the dispute, are parties to a separate agreement or treaty or where an applicable tariff, rate schedule, or other legal obligation of one of the parties provides for the parties to resolve the dispute in a manner other than in accordance with the provisions of this Appendix C of the Bylaws.

C.3 Limitations on Members' Rights To Make WECC a Party to a Dispute. In addition to the other provisions of this Appendix C of the Bylaws, any dispute (other than a dispute initiated by WECC) to which WECC is made a party shall be subject to the limitations set forth in Sections C.3.1 and C.3.2 below.

C.3.1 Bases for Using Dispute Resolution Procedures To Challenge WECC Action. Subject to any limitation set forth in these Bylaws or in applicable statute, regulation or FERC order, one or more Members may use the dispute resolution procedures specified in this Appendix C to challenge any final action of WECC only on one or more of the following bases: (i) the action is contrary to applicable law or regulation; (ii) the action is contrary to WECC's Articles of Incorporation or these Bylaws (including WECC's purposes as set forth in those documents); (iii) the action was taken in violation of applicable procedures of WECC governing that action; or (iv) the action encompasses a decision in which there was plain error material to the decision. For purposes of this Appendix C, action taken by WECC shall be deemed final if: (a) the action has been taken or adopted or approved or accepted by WECC's Board of Directors (other than by a motion specifically providing that the action is conditional or will have temporary application not to exceed six months); (b) all conditions specified to make any conditional action of WECC's Board of Directors effective have been fulfilled; or (c) the action has been taken or adopted or approved or accepted by a committee, subcommittee, task force, or other group or person acting under authority of WECC without any provision making the action subject to further approval or adoption or acceptance by the Board of Directors. Nothing contained in this Appendix C shall limit any rights any Member (or any other party) may have under applicable law or regulation to initiate or participate in an administrative or legal action to which WECC is made a party in accordance with applicable provisions of law or regulation.

C.3.2 Obligation to Bear WECC's Share of Facilitator Costs. If one or more Members initiate a dispute under this Appendix C to challenge an action of WECC, the Member(s) initiating the challenge shall be obligated to bear all of the costs of facilitators' services incurred to comply with the requirement of Section C.5 below, except to the extent WECC agrees to pay a share of the costs of facilitators' services.

C.4 Ability to Modify Dispute Resolution Procedures by Agreement. Any provision of the dispute resolution procedures set forth in this Appendix C may be modified, waived, or omitted by agreement of all of the parties to the dispute. Parties to a dispute subject to these provisions are obligated to comply with its procedures unless all of the parties to the dispute agree to do otherwise. The manner in which the dispute resolution procedures set forth in this Appendix C may be varied include (by way of example and not as limitation): the manner of selecting a facilitator or arbitrator; the procedures or time lines to be followed during mediation or arbitration; the grounds or forum or right to appeal an arbitrator's decision; the manner of allocating fees and costs associated with the dispute; whether the parties are obligated to proceed to arbitration if the dispute is not resolved through mediation; and whether a decision rendered through arbitration is binding on the parties. In addition, any dispute that does not fall within the scope specified in Section C.2 above may be resolved according to the procedures set forth in Appendix C of these Bylaws if all of the parties to the dispute agree to do so.

C.5 Mediation.

C.5.1 Notice to Other Parties and WECC's Chief Executive Officer. To initiate the dispute resolution process with respect to a dispute governed by the provisions of

this Appendix C, the Member or WECC that has elected to initiate the dispute shall deliver to all other parties to the dispute and to WECC's Chief Executive Officer (whether or not WECC is a party to the dispute) written notice invoking the dispute resolution procedures set forth in this Appendix C (a "Dispute Notice").

C.5.1.1 The Dispute Notice shall: (i) include a brief, general description of the matter(s) in dispute; (ii) include a complete list of all other Members the party submitting the Dispute Notice intends to make a party to the dispute; and (iii) state whether or not WECC is to be made a party to the dispute.

C.5.1.2 Within five business days of receiving a Dispute Notice, any party to the dispute may elect to deliver a brief supplemental description of the dispute to WECC's Chief Executive Officer.

C.5.1.3 Within 10 business days of receiving an initial Dispute Notice, WECC's Chief Executive Officer shall: (a) publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a notice containing a list of the parties to the dispute and a summary of the descriptions of the matter(s) in dispute provided by the parties to the dispute; and (b) deliver to each party to the dispute a copy of WECC's then-current standing list of qualified facilitators, knowledgeable in the matters addressed by WECC (as approved by the Board of Directors).

C.5.1.4 No person may be listed on WECC's standing list of qualified facilitators unless the person has agreed to: (i) disclose, at any time the person is selected to serve as a facilitator under this Appendix C, any personal or financial interest the facilitator may have with respect to the matter(s) in

dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the facilitator's immediate family members); (ii) disclose any relationship the facilitator may have with any party to the dispute that is not permitted under Section C.5.2 below; and (iii) abide by all applicable provisions of these Bylaws, including restrictions on disclosure of matters discussed and information exchanged during mediation as provided in Section C.5.3 below.

C.5.2 Selection of a Facilitator. Within 10 calendar days after the delivery of a Dispute Notice, the parties to the dispute shall select a neutral facilitator by mutual agreement. If the parties to the dispute cannot agree on a facilitator within 10 calendar days after delivery of a Dispute Notice, the facilitator shall be selected from WECC's standing list of qualified facilitators as follows: The parties to the dispute shall take turns striking names from WECC's standing list of qualified facilitators until there is only one name remaining. (The parties to the dispute shall draw lots to determine the order in which they take turns striking names.) The last person whose name remains on the list shall serve as the facilitator. No facilitator other than a facilitator chosen by agreement of all the parties to the dispute may (i) have a personal or financial interest in the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the facilitator's immediate family members); or (ii) be (or have an immediate family member who is) a past or present director, commissioner, officer, employee, consultant, agent, or other representative of any of the parties to the dispute. If the facilitator selected through the process of striking

names specified above is disqualified under the preceding sentence, the facilitator whose name was stricken last shall serve in his or her place. In addition, if WECC is a party to a dispute initiated by one or more Members, turns striking names from the standing list of qualified facilitators shall alternate between WECC on the one hand and all other parties to the dispute on the other.

C.5.3 Mediation Process. The facilitator and representatives of all of the parties to the dispute shall meet within 14 calendar days after the facilitator has been selected and attempt in good faith to negotiate a resolution to the dispute. Each party's representative designated to participate in the mediation process must have the authority to settle the dispute (or, at a minimum, be authorized to negotiate on behalf of the party and make recommendations with respect to settlement of the dispute if final authority to approve a settlement is reserved to a party's board, executive committee, commission, or other governing body). At the parties' initial meeting with the facilitator, the facilitator shall, after soliciting input from the parties to the dispute, set the schedule for further meetings among the parties to the dispute (subject to the 60-day maximum mediation period specified in Section C.5.6 below). The parties to the dispute shall comply with the schedule set by the facilitator and attempt in good faith at every meeting to negotiate a resolution to the dispute. To the extent permitted by law, neither the facilitator nor any party to the dispute may publicly disclose, rely on, or introduce as evidence in any subsequent arbitration, FERC proceeding, Canadian Regulatory Authority proceeding, proceeding before a Mexican Regulatory Authority, appeal, or litigation concerning the same or any related dispute: (i) any views expressed or suggestions made by another party to the dispute with respect to a possible settlement of the dispute; (ii) admissions made by another party to the dispute in the course of the mediation

proceedings; (iii) proposals made or views expressed by the facilitator; or (iv) the fact that another party to the dispute has or has not indicated willingness to accept a proposal for settlement made by the facilitator. In those cases in which a party to a dispute subject to the provisions of this Appendix C of the Bylaws is a membership organization (including WECC, if applicable), nothing in the preceding sentence shall prohibit that organization from reasonably communicating with its members and governing body to share general information about the dispute, such as the parties, status, disputed issues, and positions of each of the parties with respect to the disputed issues.

C.5.4 Referral for Resolution. With the consent of all parties to the dispute, a resolution may include referring the matter to a technical body (such as a technical advisory panel of WECC) for resolution or an advisory opinion, to arbitration, directly to FERC or, in a dispute involving a Canadian Member, directly to the appropriate Canadian Regulatory Authority, or, in a dispute involving a Mexican Member, directly to the appropriate Mexican Regulatory Authority.

C.5.5 Mediation Participation by WECC Staff When WECC Not a Party. If, during the course of mediation to which WECC is not a party, the facilitator or any party to the dispute wishes to solicit the views of WECC concerning the application, implementation, interpretation, or fulfillment of any guidelines, criteria, standards, policies, or procedures of WECC, the facilitator may request or permit the submission of WECC staff views only if: (i) any participation by WECC staff takes place exclusively in the presence of all parties to the dispute; (ii) participating WECC staff members agree to be equally available upon request to all parties to the dispute; and (iii) participating WECC staff members agree to comply with the restrictions on disclosure contained in Section C.5.3.

C.5.6 Mediation Deemed at Impasse After 60 Days. If the parties to the dispute have met and negotiated in good faith in accordance with the schedule set by the facilitator but have not succeeded in negotiating a resolution of the dispute within 60 calendar days after the first meeting with the facilitator pursuant to Section C.5.3 above, the parties to the dispute shall be deemed to be at impasse and, except as otherwise provided in Section C.5.6.2 below, shall also be deemed to have fulfilled their obligations under Section C.1 of these Bylaws to fully comply with the dispute resolution provisions before pursuing any other available remedy. If any party participating in the mediation process is subject to a contractual or statutory limitations period with respect to the matter in dispute, and the limitations period will expire before the 60-day period for mediation under this Section C.5.6 is completed, then the parties shall be deemed at impasse on the seventh calendar day preceding the expiration of the shortest applicable limitations period.

C.5.6.1 Disputes Not Subject to Provisions of Section C.6.2. Unless the matter in dispute is subject to the provisions of Section C.6.2 below, at any time after the parties to the dispute are deemed at impasse, the dispute may be submitted to binding arbitration in accordance with the procedures set forth in Section C.7 of these Bylaws (but only by agreement of all of the parties to the dispute). If the matter in dispute is subject to the provisions of Section C.6.2 below, the parties' obligations with respect to submitting the matter to binding arbitration under Sections C.6 and C.7 of these Bylaws shall be as specified in Section C.5.6.2 below. In all other cases, if the parties to the dispute do not agree to submit the dispute to binding arbitration in accordance with the procedures set forth in Section C.7 of these Bylaws, any party to the dispute may at any time thereafter pursue any other remedy available under regulation, law, or equity (subject to the restrictions on disclosure set forth in Section C.5.3 above).

C.5.6.2 Disputes Covered by Section C.6.2. If the parties to a dispute concerning a matter subject to the provisions of Section C.6.2 either: (i) are deemed at impasse after attempting to resolve the matter through mediation as provided in Sections C.5.1 through C.5.6 above; or (ii) have agreed to submit the matter directly to binding arbitration without attempting to resolve the matter through mediation as provided in Sections C.5.1 through C.5.6 above, the parties to the dispute shall submit the matter to binding arbitration in accordance with the procedures set forth in Sections C.6 and C.7 of these Bylaws.

C.5.7 Costs of Facilitator's Services. Except as otherwise provided under Section C.3.2, the costs of the facilitator's services shall be born equally by all parties to the dispute unless the parties to the dispute agree otherwise, but the parties also intend that the costs of mediation should be taken into account in any resolution proposed through the mediation process.

C.5.8 Notice to WECC of Completion of Mediation. Within 10 calendar days after either: (i) reaching a negotiated resolution through the mediation process set forth in Section C.5; or (ii) reaching deemed impasse in accordance with Section C.5.6 above, the parties to the dispute shall jointly deliver to WECC's Chief Executive Officer a written notice briefly describing the outcome of the mediation process. Promptly after receiving written notice describing the outcome of a mediation conducted in accordance with Section C.5, WECC's Chief Executive Officer shall publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a brief description of the outcome of the mediation, together with a list of all of the parties to the dispute.

C.6 General Provisions Relating to Binding Arbitration.

~~C.6.1 Matters for Which Binding Arbitration is Elective. Except with respect to any dispute that concerns one or more matters specified in Section C.6.2 below, the binding arbitration procedures set forth in Section C.7 may be invoked only by agreement of all of the parties to the dispute to be arbitrated and are solely for the convenience of WECC and its Members. If a dispute governed by this Appendix C does not concern a matter specified in Section C.6.2 below, a party to the dispute shall be deemed to have fulfilled its obligations to comply with Appendix C of these Bylaws (irrespective of whether the parties to the dispute agree to proceed with binding arbitration) to the extent that either: (i) that party has fully performed the obligations set forth in Sections C.1 through C.5.8; or (ii) all of the parties to the dispute have agreed to a different process for resolving the dispute and the agreed-upon process has been fully carried out.~~

~~C.6.2 Matters for Which Binding Arbitration Is Obligatory. If a dispute is governed by Appendix C of these Bylaws and is not resolved through the process of mediation in accordance with Sections C.5.1 through C.5.6 above, the parties shall be obligated to submit the matter to binding arbitration in accordance with the procedures set forth in Section C.7 (subject to the limitations on the arbitrator's authority set forth in Section C.6.3 below) if the dispute concerns one or more of the following matters:~~

C.6.2.1 a decision of WECC's Board of Directors or a Committee of the Board acting on the recommendation of, or on a matter within the jurisdiction of, the Operating Transfer Capability Policy Group ("OTCPG") or successor;

C.6.2.2 a transmission path rating, or a modification to a transmission path rating, assigned to one or more transmission paths operated by a Member (or jointly operated by more than one Member);

C.6.2.3 transmission access, pursuant to Sections 10.1.2, 10.1.3, and 10.5; or

C.6.2.4 any matter that, by vote of both WECC's Board of Directors and WECC's Membership, is designated as a matter to be subject to the provisions of Section C.6.2 of these Bylaws, provided that any matter submitted to WECC's Membership pursuant to this provision must be approved by at least the number of votes required to amend these Bylaws under Section 13.2.

C.6.3 Limitations on Arbitrator's Authority with Respect to Matters Specified in Section C.6.2. Unless all of the parties to a dispute agree otherwise, an arbitrator rendering a decision with respect to any matter specified in Section C.6.2 above shall have no authority to consider or award remedies for past economic harm or damages of any kind, including without limitation actual or direct damages; indirect, consequential, or incidental damages; or exemplary or punitive damages. Nothing in this Section C.6.3 shall: (i) limit any rights that a party to a dispute concerning a matter specified in Section C.6.2 above may have to pursue legal claims for damages or other economic remedies after the arbitrator has rendered his or her decision on that matter (within the scope of his or her authority under this Section C.6.3); or (ii)

limit an arbitrator's authority under Section C.8 below to shift costs or impose monetary sanctions for "good cause" (as that term is defined in Section C.8).

C.6.4 Arbitration Decisions Not To Modify Underlying Rights and Obligations. Unless all of the parties to a dispute agree otherwise, the resolution through binding arbitration of any dispute governed by this Appendix C shall not have the effect of increasing, decreasing, or otherwise modifying WECC's or any Member's obligation to abide by, or ability to enforce or impose penalties or sanctions with respect to, any guidelines, criteria, standards, policies, procedures, decisions, or Bylaws of WECC or any limitation on the foregoing, whether established by law; regulation; judicial, executive, or administrative order, decree, or decision; tariff; contract; course of performance; treaty; or otherwise.

C.6.5 Laws Relating to Binding Arbitration. WECC and its Members recognize that some Members may be subject to laws (including without limitation United States federal or state laws, Canadian or provincial laws, or Mexican laws) that limit or define those Members' ability to agree in advance to be subject to binding arbitration. If a Member has the right or obligation under applicable law to refuse to submit to binding arbitration in connection with any dispute that would otherwise be subject to binding arbitration under Section C.6.2 of these Bylaws, that Member shall not be obligated to comply with the binding arbitration procedures set forth in Sections C.6 and C.7. Any Member subject to any law or other legally binding authority that may limit (or permit the Member to limit) its obligation to comply with the provisions requiring binding arbitration under Sections C.6 and C.7 or to fully comply with a valid arbitrator's decision rendered in accordance with this Appendix

~~C shall provide notice to this effect to all other disputing parties and WECC's Chief Executive Officer upon initiation of any dispute involving that Member if the dispute is subject to Section C.6.2. Upon receiving a notice under Section C.6.5, any other party to the dispute shall thereafter be relieved of any obligation to comply with the provisions Sections C.6 and C.7 in connection with that dispute, except to the extent that the Member giving notice agrees to be fully bound by procedures governing and results of any arbitration proceeding. If there are more than two parties to a dispute covered by the preceding sentence, however, then all parties to the dispute other than the party giving notice under Section C.6.5 shall make good faith efforts to establish a mutually acceptable approach for resolving among themselves whatever aspects of the dispute can reasonably be resolved through the procedures set forth in this Appendix C without the participation of the party giving notice under Section C.6.5. If any Member fails to submit to binding arbitration, or fails to abide by a valid arbitrator's decision rendered in accordance with this Appendix C, that Member shall thereafter have no right to enforce any of the provisions of Section C.6.2 (concerning obligations to submit specified disputes to binding arbitration) against any other Member or WECC until such time as the WECC Board of Directors, or a delegate designated by the Board, determines that it is appropriate to restore the Member's ability to enforce the provisions of Section C.6.2.~~

~~C.6.6 Consistency with Laws, Regulatory Jurisdiction and Orders, Etc. Nothing contained in this Appendix C and no arbitrator's decision rendered in accordance with Section C.7 shall be construed to require or shall otherwise operate to cause~~

any Member or WECC to incur any obligation or take any action that is contrary to: (i) any applicable law or regulation; (ii) any applicable authority, order, decree, rule, or decision of a regulatory, judicial, administrative, executive, or other governmental body having jurisdiction over one or more of the matters or parties subject to this Appendix C or covered by an arbitrator's decision; or (iii) any applicable rate schedule, tariff, treaty, or valid, pre-existing contractual obligation with which any party subject to this Appendix C or covered by an arbitrator's decision is legally obligated to comply.

C.7 Arbitration Procedures.

C.7.1 Notice to WECC of Initiation of Binding Arbitration. Within 10 calendar days after all of the parties to a dispute have agreed (or become obligated under Section C.6.2 above) to submit the dispute to binding arbitration under Sections C.6 and C.7, the parties to the dispute shall deliver written notice to WECC's Chief Executive Officer (an "Arbitration Notice").

C.7.1.1 The Arbitration Notice shall: (i) include a brief, general description of the issues to be arbitrated; and (ii) identify all parties who have agreed (or become obligated) to submit the dispute to binding arbitration under Sections C.6 and C.7.

C.7.1.2 Within five business days of receiving an Arbitration Notice, WECC's Chief Executive Officer shall: (a) publish (or cause to be published) in WECC's newsletter or on its electronic bulletin board a notice containing a list of the parties to the arbitration and the parties' brief, general description of the issues to be arbitrated; and (b) deliver to each party to the dispute a

~~copy of WECC's then-current standing list of qualified arbitrators, knowledgeable in matters addressed by WECC (as approved by the Board of Directors).~~

~~C.7.1.3~~ ~~No person may be listed on WECC's standing list of qualified arbitrators unless the person has agreed to: (a) disclose, at any time the person is selected to serve as a arbitrator under this Appendix C, any personal or financial interest the arbitrator may have with respect to the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the arbitrator's immediate family members); (b) disclose any relationship the arbitrator may have with any party to the dispute that is not permitted under Section C.7.2 below; (c) assemble a complete record of the arbitration process and the materials received as evidence by the arbitrator if any of the parties to the dispute elect to appeal or contest the arbitrator's decision; and (d) abide by all applicable provisions of and procedures specified by Sections C.6 and C.7.~~

~~C.7.2~~ ~~Selection of an Arbitrator. Within 10 calendar days after all of the parties to a dispute have agreed (or become obligated) to submit the dispute to binding arbitration under Sections C.6 and C.7, the parties to the dispute shall select an arbitrator by mutual agreement. If the parties cannot agree on an arbitrator within 10 calendar days after agreeing to arbitrate their dispute, the arbitrator shall be selected from WECC's standing list of qualified arbitrators as follows: The parties to the dispute shall take turns striking names from WECC's standing list of~~

~~qualified arbitrators until there is only one name remaining. (The parties to the dispute shall draw lots to determine the order in which they take turns striking names.) The last person whose name remains on the list shall serve as the arbitrator. No arbitrator other than an arbitrator chosen by agreement of all the parties to the dispute may (i) have a personal or financial interest in the matter(s) in dispute (including any indirect personal or financial interest that could arise because of interests or relationships affecting any of the arbitrator's immediate family members); or (ii) be (or have an immediate family member who is) a past or present director, commissioner, officer, employee, consultant, agent, or other representative of any of the parties to the dispute. If the arbitrator selected through the process of striking names specified above is disqualified under the preceding sentence, the arbitrator whose name was stricken last shall serve in his or her place.~~

~~C.7.3~~ ~~Initial Statements and Proposed Arbitration Decisions.~~ ~~Within 10 calendar days after the selection of an arbitrator under Section C.7.2 above, each party to the dispute shall submit a statement in writing to all other parties to the dispute and to the arbitrator. Each disputing party's statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the party's reasonable, good faith proposal for resolving the dispute. As provided in Section C.5.3 above, to the extent permitted by law, no party to an arbitration conducted under Sections C.6 and C.7 shall publicly disclose, rely on, or introduce as evidence in any arbitration, FERC proceeding, Canadian Regulatory Authority proceeding, proceeding before a Mexican Regulatory Authority, appeal, or litigation concerning~~

the same or any related dispute any information required to be kept confidential by the terms of Section C.5.3.

C.7.4 Procedural Matters. The arbitrator shall determine discovery procedures, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. Each party to the dispute shall produce all evidence determined by the arbitrator to be relevant and material to the issues presented. If such evidence involves proprietary or confidential information, the party submitting the evidence shall petition the arbitrator for a protective order, and to the extent the arbitrator determines there is good cause the arbitrator shall issue an appropriate protective order and all parties to the dispute shall comply with the protective order. The arbitrator may elect to resolve the arbitration matter solely on the basis of written evidence and arguments.

C.7.5 Out-of-Court Sworn Testimony. At the request of any disputing party, the arbitrator shall have the discretion to allow that party to examine witnesses through sworn out-of-court testimony (referred to in the United States as "deposition" and in Canada as "discovery") to the extent the arbitrator deems the evidence sought to be relevant and appropriate. In general, out-of-court witness examinations shall be limited to a maximum of three per party and shall be held within 30 calendar days after the making of a request. Each witness examination shall be limited to a maximum of three hours' duration. The arbitrator shall have the discretion to permit the number and duration of examination sessions allowed under this Section C.7.5

to be increased, and to extend the 30-day time limit, upon request for good cause shown. All objections are reserved for the arbitration hearing except for objections based on privilege and proprietary or confidential information.

C.7.6 Intervention by Other Parties. Unless all of the parties to the dispute agree otherwise, no one (whether a Member, WECC, or any other entity or person) that is not a party to a dispute at the initiation of arbitration under Sections C.6 and C.7 shall have the right to intervene in the arbitration. Any party wishing to intervene in an arbitration under Sections C.6 and C.7 may petition the arbitrator for permission to intervene, provided that the petition is submitted to the arbitrator not more than 30 calendar days after notice of the arbitration is posted by WECC's Chief Executive Officer in accordance with Section C.7.1. The arbitrator shall have the discretion to permit a party to intervene if the arbitrator determines that the party petitioning to intervene has a direct and substantial interest in the outcome of the arbitration. In exercising his or her discretion concerning a requested intervention, the arbitrator shall also consider any additional complexity or delay that may be caused by allowing the intervention and also any other remedies available to the party requesting intervention. Any party that is granted the privilege of intervening in an arbitration under Sections C.6 and C.7 shall be permitted to intervene subject to the same terms, conditions, limitations, rights, and obligations of all other parties to the dispute, including without limitation the binding effect of arbitrator's decision, limitations on rights of appeal, the obligation to share equally in the costs of the arbitrator, and the obligation to be subject to the provisions of Section C.8.

C.7.7 Consideration of WECC Criteria, Etc. The Arbitrator shall give due consideration to the reliability criteria, standards, guidelines, policies, and procedures of WECC and the North American Electric Reliability Council (or any successor organization) to the extent they are relevant to resolution of the matter(s) in dispute. If the arbitrator's decision will include interpretation of any of WECC's reliability criteria, standards, guidelines, policies, and procedures, (and WECC is not a party to the arbitration), the arbitrator shall, before rendering his or her decision, consult with WECC (subject to the provisions of Section C.7.10 below) concerning the interpretation of WECC's applicable reliability criteria, standards, guidelines, policies, and procedures.

C.7.8 Evidence and Rebuttal. The arbitrator shall consider all issues material to the matter(s) in dispute. The arbitrator shall take evidence submitted by the parties to the dispute in accordance with procedures established by the arbitrator and may request additional information the arbitrator deems material to the resolution of the dispute. With the consent of all parties to the dispute, the arbitrator's request for additional information may include the opinion of any individual or organization with recognized expertise in the matter(s) in dispute, subject to the following conditions: (i) any verbal communication with an expert consulted by the arbitrator must take place exclusively in the presence of all parties to the dispute and copies of any written communications must be provided to all parties to the dispute; (ii) any expert consulted by the arbitrator must agree to be equally available upon request to all of the parties to the dispute; (iii) any expert consulted by the arbitrator must agree to comply with the restrictions on disclosure contained in Section C.5.3;

and (iv) all parties to the dispute shall be afforded a reasonable opportunity to question the expert and to rebut any additional information submitted by the expert at the request of the arbitrator.

C.7.9 Arbitrator's Decision. The arbitrator shall make all reasonable efforts to complete hearings (if applicable) and submissions of written evidence not more than 90 calendar days after receiving initial statements submitted under Section C.7.3 above. As soon as practicable, but in no event more than 30 calendar days after the completion of hearings and evidence submittals, the arbitrator shall render his or her final decision for resolving the dispute. By agreement of all of the parties to the dispute or at the discretion of the arbitrator for good cause, the foregoing deadline for delivery of the arbitrator's decision may be extended. The arbitrator's decision shall be based on the arbitrator's good faith determination of a resolution that will: (i) be consistent with any laws, rules, and regulations applicable to the matter(s) in dispute; (ii) be consistent with any valid pre-existing agreements among the parties to the dispute that bear on the matter(s) in dispute; (iii) not require any party to the dispute to take action that is not in compliance with any of WECC's reliability criteria, standards, guidelines, policies, and procedures; and (iv) best serve to promote or maintain reliable operation of the interconnected Bulk Electric System of the Western Interconnection, without imposing inequitable burdens or benefits on any of the parties to the dispute or others that may be affected by implementation of the arbitrator's decision. The arbitrator shall deliver to each of the parties to the dispute, along with his or her decision, a written statement including specific findings of fact, conclusions of law (if applicable), and an

explanation of the arbitrator's basis for rendering his or her decision. Subject to any protective order that may have been issued under Section C.7.4 above, WECC's Chief Executive Officer shall publish (or cause to be published) in WECC's newsletter or electronic bulletin board a brief summary of the arbitrator's decision. An arbitrator's decision that is not appealed shall not be deemed to be precedential in any other arbitration related to a different dispute.

C.7.10 WECC Staff Participation in Arbitration When WECC Not a Party. If, during the course of binding arbitration conducted under Sections C.6 and C.7 (in which WECC is not a party) the arbitrator or any party to the dispute wishes to solicit the views of WECC staff concerning the application, implementation, interpretation, or fulfillment of any guidelines, criteria, standards, policies, or procedures of WECC, the arbitrator may request or permit the submission of WECC staff views only with the consent of all of the parties to the dispute and only if: (i) any participation by WECC staff takes place exclusively in the presence of all parties to the dispute; (ii) participating WECC staff members agree to be equally available upon request to all parties to the dispute; and (iii) participating WECC staff members agree to comply with the restrictions on disclosure contained in Section C.5.3.

C.7.11 Compliance and Costs. Unless one or more of the parties to the dispute initiates and notifies all other parties to the dispute that it has initiated a process to contest or appeal the arbitrator's decision under Sections C.9 through C.13, upon the decision by the arbitrator, the parties to the dispute shall, within the time frame specified by the arbitrator, and, subject to Section C.6.6 above, take whatever action

~~is required to comply with the arbitrator's decision to the extent the arbitrator's decision does not require regulatory action. To the extent the arbitrator's decision affects jurisdictional rates, terms and conditions of service, or facilities or otherwise requires local, state, federal, or provincial approval or regulatory action, or a FERC filing or a Canadian Regulatory Authority filing by a Canadian Member or a Mexican Regulatory Authority filing by a Mexican Member, the affected Member (or WECC, if WECC is the party with the obligation to seek regulatory action) shall, within the time frame specified by the arbitrator, submit the arbitrator's decision or an appropriate filing to implement the arbitrator's decision and support the appropriate authority's acceptance or approval of the arbitrator's decision or implementation filing, except in cases where any party to the dispute has given notice of its intent to contest or appeal the arbitrator's decision. All costs associated with the arbitration (not including costs associated with attorney and expert witness fees incurred by the parties to the dispute) shall be divided equally among the parties to the dispute unless: (i) all of the parties to the dispute agree to an alternate method of allocating costs; or (ii) in rendering his or her decision, the arbitrator exercises his or her discretion under Section C.8 below to assess fees, costs, or other monetary sanctions against one or more of the parties to the dispute for good cause.~~

~~C.7.12~~ ~~Entry of Judgment.~~ ~~At any time after an arbitrator has rendered his or her decision in an arbitration conducted under Sections C.6 and C.7 (provided that the time provided for initiating an appeal under Sections C.11.1 and C.12 below has expired and no appeal or other means of contesting the arbitrator's decision has been initiated), judgment on the decision rendered by the arbitrator may be entered by~~

any court of competent jurisdiction (subject to the provisions of Sections C.6.3, C.6.4, and C.6.6 above). If the award is against the United States, a party to the arbitration may apply to the United States District Court for the district in which the principal office of the applicable United States department or agency is located for an order confirming the award pursuant to 5 U.S.C. § 580.

C.8 Arbitrator's Discretion to Shift Costs or Impose Sanctions for Cause. Each party to any dispute submitted to arbitration under Sections C.6 and C.7 shall bear its own costs and fees associated with representation and participation in the arbitration process, and shall share equally in the arbitrator's fees except that the arbitrator shall have the discretion, to the extent permitted by law, to require one or more of the parties to the dispute to pay part or all of the costs and fees (including without limitation attorneys' and arbitrator's fees) of one or more other parties to the dispute, or to impose monetary sanctions on some other basis that is reasonable under the circumstances, for good cause. As used in this Section C.8, "good cause" means conduct involving serious abuse of or failure to comply with the dispute resolution process set forth in this Appendix C, willfully undertaken to harass or delay other parties to the dispute or to substantially impede the arbitrator's ability to render a decision consistent with the provisions set forth in Section C.7.9.

C.9 Rights to Appeal Arbitration Decisions. Except to the extent otherwise provided by applicable United States state or federal law, applicable Canadian or provincial law, or applicable Mexican law, a party to a dispute resolved by arbitration under Sections C.6 and C.7 may appeal or contest the arbitrator's decision only on one or more of the bases specified in Section C.9.1 below and only in accordance with the procedures set forth in Sections C.9.2 through C.13.

~~C.9.1 Grounds for Appealing Arbitration Decisions. A party to a dispute resolved by arbitration under Sections C.6 and C.7 may contest or appeal the arbitrator's decision only on the basis that: (i) the arbitrator's decision is contrary to applicable law or regulation (including without limitation the FPA or FERC's then-applicable standards or policies, or comparable types of provisions that may apply under applicable Canadian, provincial, Mexican, or other laws and regulations); (ii) the arbitrator's decision is demonstrably arbitrary and capricious and without support in the record assembled during the arbitration; (iii) the arbitrator failed to afford one or more parties to the dispute an opportunity for a fair and meaningful hearing; (iv) the arbitrator engaged in serious misconduct in connection with the arbitration; (v) the arbitrator exceeded the authority conferred upon him or her under this Appendix C or as otherwise established by agreement of all the parties to the dispute; or (vi) the arbitrator's decision is contrary to the provisions of Section C.6.6.~~

~~C.9.2 Matter and One or More Parties to Dispute Subject to FERC Jurisdiction. If (i) the subject matter of a dispute arbitrated under Sections C.6 and C.7 is within the jurisdiction of FERC, and (ii) the conditions specified in Section C.12.1 or C.12.2 are satisfied, the rights of the parties to contest or appeal the arbitrator's decision shall be as set forth in Sections C.10 and C.12 below (subject also to the provisions of Section C.9.1 above). Notwithstanding the foregoing, nothing herein shall be construed or operate to require any Canadian or Mexican party or any other party that is not a "public utility" within the meaning of the FPA to make any filing with FERC under Sections 205 or 206 of the FPA.~~

C.9.3 All Parties and Matters in Dispute Subject to Jurisdiction of a Canadian Regulatory Authority. If all of the parties to an arbitrated dispute are subject to the jurisdiction of a particular Canadian Regulatory Authority, and if all matters in dispute are also subject to the jurisdiction of the same Canadian Regulatory Authority, any disputing party may appeal an arbitrator's decision to that Canadian Regulatory Authority, where such Canadian Regulatory Authority has jurisdiction to hear the appeal, or to the appropriate Canadian court. Any appeal to a Canadian Regulatory Authority or Canadian court shall be subject to the provisions set forth in Sections C.10 and C.11 below.

C.9.4 All Parties and the Matter in Dispute Subject to Jurisdiction of a Mexican Regulatory Authority. If all of the parties to an arbitrated dispute are subject to the jurisdiction of a particular Mexican Regulatory Authority, and if all matters in dispute are also subject to the jurisdiction of the same Mexican Regulatory Authority, any disputing party may appeal an arbitrator's decision to the appropriate Mexican Regulatory Authority, subject to the provisions set forth in Sections C.10 and C.11 below.

C.9.5 Appeal to Court. If none of the preceding provisions concerning appealing or contesting an arbitrator's decision before FERC, a Canadian Regulatory Authority, or a Mexican Regulatory Authority apply to an arbitrated dispute, any party to an arbitrator's decision rendered in accordance with the provisions of Sections C.6 and C.7 may appeal the arbitrator's decision to a court of competent jurisdiction as provided under Section C.13 below.

C.10 Appealing or Contesting Arbitrator's Decision to FERC or a Presiding Authority. Subject to the conditions specified in Sections C.9.1 through C.9.5 above, any disputing party may appeal or contest an arbitrator's decision to FERC or an appropriate Presiding Authority as follows:

C.10.1 Record on Appeal. Except as otherwise provided in Section C.10.3 below, any appeal or action to contest an arbitrator's decision to FERC or a Presiding Authority shall be based solely upon the record assembled by the arbitrator. All parties to arbitrations conducted under Sections C.6 and C.7 intend that: (i) the FERC or other Presiding Authority should afford substantial deference to the factual findings of the arbitrator; (ii) the portion, if any, of the arbitrator's decision relating to issues not of first impression (i.e., matters previously decided by the FERC or other Presiding Authority or a court of competent jurisdiction in cases involving comparable facts and circumstances) should be afforded appropriate deference by the FERC or other Presiding Authority; and (iii) the portion, if any, of the arbitrator's decision relating to issues of first impression should be afforded no deference by the FERC or other Presiding Authority.

C.10.2 No Expansion of Record on Appeal. Except as otherwise provided in Section C.10.3 below, no Member, non-Member, or WECC that has been a party to an arbitration under Sections C.6 and C.7 shall seek to expand the factual record before FERC or a Presiding Authority beyond that assembled by the arbitrator.

C.10.3 Exceptions to Limitations on Record on Appeal. If the arbitrator fails to assemble a complete record of the evidence submitted with respect to an arbitrated decision that is appealed pursuant to Sections C.9 through C.13, the parties to the appeal

shall, notwithstanding the provisions of Sections C.10.1 and C.10.2 above, have the right to supplement the arbitrator's record before FERC or the Presiding Authority with any materials received into evidence by the arbitrator but omitted from the record assembled by the arbitrator. If an arbitrator's decision is appealed under Section C.9.1(iii) or (iv) above on the grounds that the arbitrator improperly excluded evidence so as to materially prejudice the outcome of the arbitration with respect to one or more of the parties to the dispute, any party to the appeal may submit the evidence asserted to be improperly excluded, but only as a basis to request that FERC or the Presiding Authority vacate the arbitrator's decision and remand the matter to the arbitrator (or, if FERC or the Presiding Authority determines that the arbitrator engaged in serious misconduct, to a newly selected arbitrator) for reconsideration of the matter with inclusion of the improperly excluded evidence. If an arbitrator's decision is appealed under Section C.9.1(iv) above on the grounds of serious misconduct by the arbitrator, any party to the appeal may offer new evidence relating to the arbitrator's alleged misconduct.

C.11 Procedures for Appeals to Presiding Authority. If any party to an arbitration under Sections C.6 and C.7 desires to appeal an arbitrator's decision to an appropriate Presiding Authority, it shall provide written notice to that effect to all other parties to the arbitration, the arbitrator, and WECC's Chief Executive Officer within 14 calendar days following the date of the arbitrator's decision. If notice of appeal is timely provided:

C.11.1 Within 30 calendar days after the date of the appealing party's first notice of appeal, the party providing notice of appeal shall file its statement of position regarding the appeal with the Presiding Authority, together with the complete evidentiary record

of the arbitration and a copy of the arbitrator's decision. The statement of position shall state that the appeal requested has been the subject of an arbitration pursuant to this Agreement.

C.11.2 Within 30 calendar days after the date of the appealing party's first notice of appeal, any other party that was a party to the arbitration may file its statement of position regarding the appeal with the Presiding Authority.

C.11.3 Copies of all materials filed with the Presiding Authority by any party during the course of an appeal shall be delivered to all other parties to the arbitration and to WECC's Chief Executive Officer.

C.11.4 Implementation of the arbitrator's decision shall be deemed stayed pending an appeal unless and until, at the request of a disputing party, the Presiding Authority issues an order shortening or extending the stay of implementation.

C.11.5 WECC's Chief Executive Officer shall publish (or cause to be published) a summary of each appeal in WECC's newsletter or electronic bulletin board.

C.11.6 The Members and WECC intend that any Presiding Authority's order resulting from an appeal under Sections C.9 and C.11 shall be subject to judicial review pursuant to laws governing the Presiding Authority and the matter in dispute that provide for judicial review of Presiding Authority action.

C.12 Procedures for Contesting or Appealing Arbitrator's Decision Before FERC. If any party to a dispute arbitrated under Sections C.6 and C.7 elects, subject to the limitations set forth in Sections C.9.1 through C.9.5 above, to contest or appeal an arbitrator's decision before FERC, the party so electing shall provide written notice to that effect to all other parties to the arbitration, the arbitrator, and WECC's Chief Executive Officer within 14 calendar

days following the date of the arbitrator's decision. The provisions contained in Sections C.10.1, C.10.2, and C.10.3 above shall apply with respect to the record of the arbitration submitted to FERC. In addition, the following provisions shall apply:

C.12.1 FERC Filing by Prevailing Party. If the arbitrator's decision requires the prevailing party to take action that must have FERC approval or involves the provision of FERC-jurisdictional service by the prevailing party, the prevailing party shall file the arbitrator's decision or make an appropriate filing with FERC to implement the arbitrator's decision. Provided that it has given notice as required under Section C.12 above, any non-prevailing party may contest the prevailing party's filing in accordance's with FERC's applicable rules and regulations.

C.12.2 Complaint to FERC by Prevailing Party. If the arbitrator's decision requires a non-prevailing party to take action that must have FERC approval or involves the provision of FERC-jurisdictional service by any non-prevailing party, then, if the non-prevailing party has given notice as required under Section C.12 above, the prevailing party may submit the arbitrator's decision to FERC in the form of a complaint.

C.13 Appeal to Court. If none of the provisions that govern appealing or contesting an arbitrator's decision before FERC, a Canadian Regulatory Authority, or a Mexican Regulatory Authority as set forth in Sections C.9.2, C.9.3, or C.9.4 above apply, any disputing party may appeal an arbitrator's decision to any court of competent jurisdiction, subject to the conditions specified in Section C.9.1 above. Except as otherwise provided in Section C.10.3 above (substituting the words "court of competent jurisdiction" for "FERC or the Presiding Authority"), any appeal to a court shall be based solely upon the

~~record assembled by the arbitrator, and no Member, non-Member, or WECC who is a party to an arbitration under Sections C.6 and C.7 shall seek to expand the factual record before the court beyond that assembled by the arbitrator.~~

Appendix of Additional Definitions Relating to Alternative Dispute Resolution Provisions

Arbitration Notice has the meaning specified in Section C.7.1 of these Bylaws.

Canadian Regulatory Authority. The agency or agencies established under the laws of Canada or the applicable Provinces of Canada and having jurisdiction over facilities, interconnections, transmission rates, charges, terms, and conditions of service of a Canadian Member.

Dispute Notice has the meaning specified in Section C.5.1 of these Bylaws.

FERC. The Federal Energy Regulatory Commission or a successor agency.

FPA. The Federal Power Act (16 U.S.C. §§ 824 *et. seq.*), as it may be amended from time to time.

Mexican Regulatory Authority. The agency or agencies established under the laws of Mexico or the applicable states of Mexico and having jurisdiction over facilities, interconnections, transmission rates, charges, terms, and conditions of service of a Mexican Member.

Presiding Authority. As used in Sections C.10 and C.11, the term "Presiding Authority" has the following meanings: with respect to an appeal to an appropriate Canadian Regulatory Authority, "Presiding Authority" means the presiding Canadian Regulatory Authority or Canadian court with jurisdiction to hear the appeal; and with respect to an appeal to an appropriate Mexican Regulatory Authority, "Presiding Authority" means the presiding Mexican Regulatory Authority or Mexican court with jurisdiction to hear the appeal.

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 VAR-001-5

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September 6, 2018

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Exhibit C Standard Drafting Team Roster for Project WECC-0128, VAR-001-4.1, Voltage and Reactive Control – WECC Regional Variance, Five-Year Review

UNITED STATES OF AMERICA
BEFORE THE
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PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD VAR-001-5

Pursuant to Section 215(d)(1) of the Federal Power Act[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard VAR-001-5 – Voltage and Reactive Control. NERC is proposing revisions only to the regional Western Electricity Coordinating Council ("WECC") Variance to the standard, which applies to entities in the Western Interconnection.

NERC requests that the Commission approve proposed Reliability Standard VAR-001-5 (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the proposed effective date as described herein and in Exhibit A. Lastly, NERC requests approval of the associated Violation Severity Levels ("VSLs") and Violation Risk Factors ("VRFs"), both of which remain substantively unchanged from the currently-effective version of the standard.

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1 16 U.S.C. § 824o (2018).

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 Federal Power Act on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 F.E.R.C ¶ 61,062 (2006).

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standard and a summary of the development proceedings (**Exhibit B**). The proposed standard continues to meet the criteria for approval identified by the Commission in Order No. 672.[6] In accordance with NERC's Rules of Procedure, the Variance revisions reflected in proposed Reliability Standard VAR-001-5 were developed through WECC's standard development process. The proposed standard was approved by the WECC Board of Directors on June 20, 2018 and by the NERC Board of Trustees on August 16, 2018.

I. EXECUTIVE SUMMARY

The purpose of VAR-001-5 is to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection. In 2013, the Commission approved the Variance for the WECC region.[7] In 2017, WECC initiated a periodic review of the Variance and, as a result of this review, determined that certain revisions were necessary.

As explained more fully herein, WECC has revised the Variance to eliminate Requirement E.A.15 because the reliability-related task is addressed in a continent-wide Reliability Standard. Additionally, WECC has made several minor changes to the standard and associated elements, including correcting typographical and capitalization errors, updating the Measures to match NERC conventions, and replacing the term "shall" with "will." No revisions were made to the

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5 18 C.F.R. § 39.5(a).

6 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, F.E.R.C Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, F.E.R.C Stats. & Regs. ¶ 31,212 (2006).

7 *N. Am. Elec. Reliability Corp.*, Docket No. RD13-6-000 (June 20, 2013) (delegated letter order approving VAR-001-3, which modified VAR-001-2 to add the WECC Variance) (hereinafter "2013 Approval Order").

continent-wide Requirements or any of the corresponding elements. The revised WECC Variance in proposed Reliability Standard VAR-001-5 continues to remain more stringent than the continent-wide Requirements it replaces and continues to provide an alternate approach to meeting the same reliability objective based on physical differences in the Western Interconnection. For these reasons, and as discussed more fully herein, NERC respectfully requests the Commission approve proposed Reliability Standard VAR-001-5 and the associated elements. The following petition presents the justification for approval and supporting documentation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

The following background information is provided below: (a) an explanation of the regulatory framework for NERC and Regional Reliability Standards; (b) an explanation of the WECC standards development process; and (c) the history of Project WECC-0128, VAR-001-4.1, Voltage and Reactive Control – WECC Regional Variance, Five-year Review**.**

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 Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the Federal Power Act states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the Federal Power Act authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has 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. A Reliability Standard proposed by a Regional Entity must meet the same standard that NERC's Reliability Standards must meet, *i.e.*, the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[12]

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8 16 U.S.C. § 824o (2018).

9 *Id.* § 824o(b)(1).

10 *Id.* § 824o(d)(5).

11 18 C.F.R. § 39.5(a).

12 16 U.S.C. § 824o(d)(2); 18 C.F.R. §39.5(a). If the regional Reliability Standard is proposed by a Regional Entity organized on an Interconnection-wide basis, to be applicable on an Interconnection-wide basis, then NERC must rebuttably presume that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. 16 U.S.C. § 824o(d)(3); 18 C.F.R. §39.5(b).

In Order No. 672, the Commission stated that it would accept two types of regional differences, provided that they were otherwise just, reasonable, not unduly discriminatory or preferential in the public interest. Specifically, the Commission stated it would accept regional differences that are: (1) more stringent than the continent-wide Reliability Standard, or (2) necessitated by a physical difference in the Bulk-Power System.[13] A regional difference generally takes one of two forms: (1) a regional Variance may be included in a continent-wide Reliability Standard, which achieves the reliability objective of the continent-wide standard's requirement(s) in an alternate way than specified in a given Requirement in the continent-wide standard; or (2) a separate Regional Reliability Standard may be developed, which adds one or more Requirements without altering any continent-wide Requirements that are applicable to entities in the region.

Pursuant to Section 215(d)(2) of the Federal Power Act[14] and Section 39.5(c)[15] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard and to the technical expertise of a Regional Entity organized on an Interconnection-wide basis with respect to a Reliability Standard to be applicable within that Interconnection.

B. WECC Regional Reliability Standards Development Process

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved NERC Standard Processes Manual[16] and the WECC

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13 Order No. 672 at P 291.

14 16 U.S.C. § 824o(d)(2).

15 18 C.F.R. § 39.5(c)(1).

16 Section 9.0 of the NERC Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure, provides that any Variance that is proposed to apply to 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 standard development procedure. The NERC Standard Processes Manual is available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

Reliability Standards Development Procedures ("RSDP").[17] WECC's RSDP provides for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Regional Reliability Standards and Variances and thus addresses certain of the criteria for approval. The development process is open to any person or entity that is an interested stakeholder. WECC considers the comments of all stakeholders, and a vote of stakeholders and the WECC Board of Directors is required to approve a Regional Reliability Standard or Variance. Once the standard is approved by the WECC Board of Directors, NERC posts the approved Regional Reliability Standard or Variance for an additional comment period. Then the NERC Board of Trustees must adopt the Regional Reliability Standard or Variance before it is submitted to the Commission for approval.

C. Relevant Commission Approval History

The Commission approved the first version of the VAR-001 WECC Variance in 2013, in standard version VAR-001-3.[18] The Variance removed Requirement R3 and replaced Requirement R4 of Reliability Standard VAR-001-2 for applicable entities in the Western Interconnection. The Variance was originally developed to allow Generator Operators in the Western Interconnection to better assist in controlling system voltage during steady-state and outage conditions.

The Commission approved the last substantially-revised version of the standard, Reliability Standard VAR-001-4, in 2014.[19] The Commission approved the currently-effective version of the VAR-001 standard, VAR-001-4.2, in 2017.[20] VAR-001-4.2 contains several errata changes from

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17 The currently-effective WECC RSDP was approved by the Commission on October 27, 2017 (*see N. Am. Elec. Reliability Corp.*, RR17-5-000 (Oct. 27, 2017) (delegated letter order)) and is available at http://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/WECC%20RSDP_20171027.pdf.

18 2013 Approval Order, supra n. 7.

19 *N. Am. Elec. Reliability Corp.*, Docket No. RD14-11-000 (Aug. 1, 2014) (delegated letter order).

20 *N. Am. Elec. Reliability Corp.*, Docket No. RD17-7-000 (Sep. 26, 2017) (delegated letter order).

the previous version of the standard. The intermediate versions of the VAR-001 standard did not substantively modify the WECC Variance.

D. Development of the Proposed Reliability Standard

As further described in Exhibit B hereto, proposed Reliability Standard VAR-001-5 was developed as part of a Five-year review of the WECC Variance. On May 9, 2018, the standard was approved by the WECC ballot body with 100 percent affirmative vote. The WECC Board of Directors approved the standard (specifically, the retirement of Variance Requirement E.A.15) on June 20, 2018. NERC posted proposed VAR-001-5 for a 45-day comment period concluding on August 6, 2018. Commenters agreed that WECC's process was open, inclusive, balanced, transparent, and that due process was followed, and there were no additional changes after this comment period. The NERC Board of Trustees subsequently adopted the standard on August 16, 2018.

IV. JUSTIFICATION FOR APPROVAL

The purpose of proposed Reliability Standard VAR-001-5 is to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection. The WECC Variance allows Generator Owners in the Western Interconnection to better assist in achieving this reliability goal. The currently-effective Variance deletes in its entirety continent-wide Requirement R4, which requires Transmission Operators to specify the criteria that will exempt generators from following a voltage or Reactive Power schedule, from having its automatic voltage regulator in service or from being in control mode, or from having to make any associated notifications. The Variance also replaces continent-wide Requirement R5, which requires each Transmission Operator to specify either a voltage or Reactive Power schedule, with Variance

Requirements pertaining to voltage schedules. In proposed Reliability Standard VAR-001-5, NERC proposes revisions to this Variance to eliminate a duplicative requirement, correct errors, and match current conventions. As revised, the WECC Variance remains more stringent than its continent-wide counterpart and necessary for reliability in the Western Interconnection. It also continues to satisfy the Order No. 672 criteria for approval. The proposed changes are discussed in more detail below.

A. Elimination of Requirement E.A.15

In the WECC Variance in proposed Reliability Standard VAR-001-5, Variance Requirement E.A.15 is removed, and the subsequent Requirements have been renumbered accordingly. In the currently-effective standard, this Variance Requirement provides that each Generator Operator shall convert each voltage schedule issued to it by the Transmission Operator per Variance Requirement E.A.13 into the voltage set point for the generator excitation system. Since the original WECC Variance was approved in 2013, NERC revised the continent-wide VAR-002 standard. Reliability Standard VAR-002-4.1 - Generator Operation for Maintaining Network Voltage Schedules now addresses the same reliability-related task, which is for the Generator Operator to have a means of converting the scheduled voltage specified by the Transmission Operator to the voltage set point being monitored by the Generator Operator. Reliability Standard VAR-002-4.1 Requirement R2 Part 2.3 provides as follows:

> R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.
>
> ***
>
> **2.3.** Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a

> methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.[21]

As the continent-wide Requirement now addresses the same reliability task as current WECC Variance Requirement E.A.15, the WECC Variance Requirement should be removed from the Variance as redundant. As a redundant Requirement, its removal will have no adverse impact on reliability in the Western Interconnection.

B. Other Revisions

The revised WECC Variance in proposed Reliability Standard VAR-001-5 reflects additional non-substantive revisions, including updating the document format and correcting the capitalization of the term "Area" in Variance Requirement E.A.14 to lower case "area", as the term is not defined in the *Glossary of Terms Used in NERC Reliability Standards*. Additionally, and as discussed in the following section, the Variance VSL Table has been updated and the Measures moved and revised to match current conventions.

V. Enforceability of Proposed Reliability Standard VAR-001-5

The revised WECC Variance in proposed Reliability Standard VAR-001-5 includes VRFs and VSLs. The VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated requirement is violated. The VRFs assess the impact to reliability of violating a specific requirement. The VRFs and VSLs for the proposed standard comport with NERC and Commission guidelines related to their assignment. The VRFs and VSLs for the WECC Variance remain substantively unchanged from the currently-effective version of the standard, except that the VSLs have been updated to reflect renumbering of the Variance

[21] Reliability Standard VAR-002-4.1 Requirement R2 (internal footnotes omitted).

Requirements. As no changes to the continent-wide Requirements are proposed in VAR-001-5, the VRFs and VSLs corresponding to those Requirements remain unchanged.

The proposed Reliability Standard also includes Measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These Measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[22] In proposed VAR-001-5, the WECC Variance Measures have been updated to match current conventions, including moving each Measure to immediately below the corresponding Variance Requirement, and replacing the term "shall" with "will". No changes have been made to the Measures corresponding to the continent-wide Requirements as those Requirements remain unchanged.

VI. EFFECTIVE DATE

NERC respectfully requests that the Commission approve proposed Reliability Standard VAR-001-5 to be effective the first day of the first calendar quarter following Commission approval. The currently-effective standard version VAR-001-4.2 would be retired immediately prior to the effective date of the new standard.

[22] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VII. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Reliability Standard VAR-001-5 in **Exhibit A**;
- the other associated elements in the Reliability Standard in **Exhibit A**, including the VRFs and VSLs;
- the proposed effective date, as described herein and in **Exhibit A**; and
- the retirement of currently-effective Reliability Standard VAR-001-4.2.

Respectfully submitted,

/s/ Lauren Perotti

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Counsel for the North American Electric Reliability Corporation

Date: September 6, 2018

Exhibit A

Proposed Reliability Standard VAR-001-5 – Voltage and Reactive Control

Clean Version

Proposed Reliability Standard VAR-001-5 – Voltage and Reactive Control

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-5

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to

			“area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Redline Version

Proposed Reliability Standard VAR-001-5 – Voltage and Reactive Control

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-~~4.2~~5

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its ~~Area~~area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

~~**E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*~~

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains

notification to the Generator Operator of the voltage schedule reference point for each generation resource.

~~E.A.16~~E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~E.A.17~~E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~E.A.18~~E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

~~Measures~~[~~1~~]

~~M.E.A.13~~ ~~Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing~~

[~~1~~] ~~The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.~~

~~the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.~~

~~**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.~~

~~**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.~~

~~**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~**M.E.A.18**~~**M.E.A.17** If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator ~~shall~~will have~~ and provide upon request,~~ evidence that it met the control loop specifications in sub-parts E.A.~~18~~17.1 through E.A.~~18~~17.2~~. Design~~, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation~~ are acceptable as evidence.~~.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~E.A.15~~	~~The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.~~
E.A.~~16~~15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.~~17~~16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.~~18~~17	N/A	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 through ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January~~,~~ 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised

3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 "Area" was changed to "area."; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing "shall" with "will"; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Exhibit B

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

Proposed Reliability Standard VAR-001-5 reflects revisions to the WECC Variance in currently-effective Reliability Standard VAR-001-4.2. In accordance with the NERC Standard Processes Manual, the proposed standard containing the revised Variance was developed in accordance with the WECC Reliability Standards Development Procedure.

The development record for proposed Reliability Standard VAR-001-5 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 Electric Reliability Organization ("ERO").[1] For the proposed standard, the technical expertise of the ERO is derived from the standard drafting team selected by the WECC Standards Committee to lead the project in accordance with Step 3 of the WECC Reliability Standards Development Procedures. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit C**.

II. Standard Development History

A. Standard Authorization Request Development

Project WECC-0128 VAR-001- 4.1 – Voltage and Reactive Control, WECC Regional Variance Five-year Review[2] was initiated on June 8, 2017 with receipt of a proposed Standards Authorization Request ("SAR"). The WECC Standards Committee ("WSC") formally approved the SAR on July 6, 2017 and created a standard drafting team on September 5, 2017.

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824o(d)(2) (2012).

[2] The project was later known as WECC-0128 VAR-001-4.2, Voltage and Reactive Control – WECC Regional Variance, Five-year Review.

B. First Posting – Comment Period

On September 20, 2017, the standard drafting team agreed by majority vote to post proposed Reliability Standard VAR-001-5 for a 45-day public comment period.[3] Proposed Reliability Standard VAR-001-5 was posted from September 25, 2017 through November 10, 2017. WECC received comments from three entities. Based on the comments received, the standard drafting team determined to make substantive changes to the proposed standard. Therefore, the proposed standard was posted for an additional comment period.

C. Second Posting – Comment Period

Proposed Regional Reliability Standard VAR-001-5 was posted for a 30-day public comment period from December 22, 2017 to January 22, 2018.[4] WECC received comments from two entities. Based on the comments received, the standard drafting team agreed by a majority of those present to forward the project to the WSC with a request for ballot.

D. Ballot Period and Results

On March 6, 2018, the WSC approved the request for ballot. The ballot pool opened on April 2, 2018 and closed on April 16, 2018. WECC held a Standards Briefing on April 13, 2018. Thirty-three individuals joined the ballot pool. The ballot was open from April 18, 2018 through May 9, 2018. Thirty-two individuals cast votes, reaching quorum at 96.97%. The regional standard obtained thirty-two affirmative votes,[5] which was 100% of the weighted segment vote. On June 19, 2018, the WSC approved the standard for WECC Board of Directors disposition.

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[3] Notice of VAR-001-WECC-4.1 Voltage and Reactive Control Five-Year Review Posting 1 is available at https://www.wecc.biz/Administrative/WECC-0128%20Posting%201%20Notice%20of%20Posting%20for%20Comment.pdf.

[4] Notice of VAR-001-WECC-4.1 Voltage and Reactive Control Five-Year Review Posting 2 is available at https://www.wecc.biz/Administrative/WECC-0128%20Posting%202%20Notice%20of%20Posting%20for%20Comment.pdf.

[5] During the ballot period there were 32 abstentions and 1 individual did not cast a vote.

E. WECC Board of Directors Approval

On June 20, 2018, the WECC Board of Directors approved the revisions to the WECC Variance reflected in proposed Reliability Standard VAR-001-5.

F. NERC Comment Period and Board of Trustees Adoption

NERC posted proposed Reliability Standard VAR-001-5 for a 45-day public comment period from June 22, 2018 to August 6, 2018.[6] The NERC Board of Trustees adopted proposed Reliability Standard VAR-001-5 on August 16, 2018.[7]

[6] The NERC web page for Regional Reliability Standards Under Development is available at http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx.

[7] NERC, *Board of Trustees Agenda Package*, Agenda Item 7e (VAR-001-5 – Voltage and Reactive Control), *available at* https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_August_16_2018.pdf.

Complete Record of Development

Steven Rueckert
155 North 400 West
Salt Lake City, Utah 84103

August 31, 2018

Subject: Notification of Completion
VAR-001-5[1]
Automatic Voltage Regulators (AVR)
WECC Regional Variance

To: Mr. Howard Gugel
Senior Director of Standards
North American Electric Reliability Corporation (NERC)
3353 Peachtree Rd. NE, North Tower–Suite 600
Atlanta, GA 30326

Dear Howard,

WECC is seeking approval by the NERC Board of Trustees, with subsequent disposition by the Federal Energy Regulatory Commission (FERC), to approve VAR-001-5, Voltage and Reactive Control, with modification to the WECC Regional Variance.

Per the Western Electricity Coordinating Council's (WECC) Reliability Standards Development Procedures (Procedures), the VAR-001-5 Drafting Team conducted a five-year review of VAR-001-4.2, Automatic Voltage Regulators with WECC Regional Variance, making the following proposed changes:

- In E.A.14, corrected "Area" to "area."
- E.A.15 and associated elements were eliminated because the reliability-related task required in E.A.15 is contained as a lesser included task of VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3. This finding by the drafting team agrees with the recent findings of the NERC Standards Efficiency Review (SER) Team and is included in the draft SER Standards Authorization Request.
- Updated Measures and moved matching current NERC conventions, replacing "shall" with "will."
- Corrected typographical errors in VSL Table for E.A.17.
- Updated the format and numbering.

Thank you for your assistance.

Sincerely,

Steven Rueckert
Director of Standards
Western Electricity Coordinating Council

[1] Numbering is subject to NERC assignment.

Supporting Documentation
WECC-0128 VAR-001-4.2
Voltage and Reactive Control with Regional Variance
Five-year Review

For documentation support please contact W. Shannon Black, at (503) 307-5782.

WECC-0128 VAR-001-4.2
Voltage and Reactive Control with Regional Variance
Five-year Review

	QR	BOT	Gov't Auth.*
SAR–Standard Authorization Request Attachment A			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment A Standard Authorization Request			
Regional Reliability Standard(s) (Clean Existing) Attachment B			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment B Clean Existing			
Regional Reliability Standard(s) (Clean Proposed) Attachment C			
File Name: WECC-0128 VAR-001-5 Five-year Review Attachment C Clean Proposed			
Regional Reliability Standard(s) (Existing redlined to Proposed) Attachment D			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment D Existing redlined to Proposed			
Project Roadmap Attachment E			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment E Project Roadmap			
Implementation Plan Attachment F			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment F Implementation Plan			
Regional Reliability Standard Submittal Request Attachment G			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment J Regional Reliability Standard Submittal Request			
Order 672 Criteria Attachment H			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment K Order 672 Criteria			
Drafting Team Roster with Biographies Attachment I			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment L Drafting Team Roster			
Ballot Pool Members Attachment J			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment M Ballot Pool Members			

Supporting Documentation
WECC-0128 VAR-001-4.2
Voltage and Reactive Control with Regional Variance
Five-year Review

Final Ballot Results Attachment K			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment N *Final Ballot Results*			
Minority Issues Attachment L			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment P *Minority Issues*			
WECC Standards Committee Roster Attachment M			
File Name: WECC-0128 VAR-001-4.2 Five-year Review Attachment Q *WECC Standards Committee Roster*			
Responses to Comments–WECC Attachment N			
File Name: WECC-0128 VAR-001-4.2 Five-year Review *Attachment N1–Posting 1 Response to Comments* *Attachment N2–Posting 2 Response to Comments*			

Attachment A
Standard Authorization Request
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

This Standard Authorization request (SAR) was received on June 8, 2017, and deemed complete the same day. The SAR will be vetted for approval during the June 2017 WECC Standards Committee meeting.

Introduction

This project is a five-year review of the WECC Regional Variance as required by the Reliability Standards Development Procedures (Procedures).

Requester Information

1. Provide your contact information and your alternates contact information:
   - Your First Name: W. Shannon
   - Your Last Name: Black
   - Your Email Address: sblack@wecc.biz
   - Your Phone Number: (503) 307-5782
   - Organization Name: WECC
   - Alternates First Name: Steven
   - Alternates Last Name: Rueckert
   - Alternates Email Address: steve@wecc.biz
   - Alternates Phone Number: (801) 883-6878

Type of Request

2. Specify the type of request: (select one)
   - Request for Five-year Review of a WECC Regional Variance to a NERC Standard.

Create, Modify or Retire a Document Questions

Provide the requested information for your request to create, modify, or retire the document.

3. Requested Action: (select one)
   - Request for Five-year Review of a WECC Regional Variance to a NERC Standard.
4. Document Type: (select one)
   - WECC Regional Variance to a NERC Standard.

5. Issue: Specify what industry problem this request is trying to resolve.

   In accordance with the WECC Reliability Standards Development Procedures, Maintenance of RRS and Ops Documents, "The WSC shall ensure that each RRS is reviewed at least once every five years from the effective date of the most recent version of the RRS."

   The WECC Regional Variance was: 1) developed as WECC-0046, 2) approved by the NERC Board of Trustees on May 9, 2012, and 3) FERC approved on June 20, 2013.

   Changes to language outside of the Regional Variance are not within the scope of this request.

   Proposed Remedy: Specify how this request proposes to address the issue described.

   The assigned drafting team should review the document in its entirety with specific consideration for recommendations provided by NERC in its Periodic Review Recommendations for VAR-001-4.1 - Voltage and Reactive Control, May 19, 2017.

   Those recommendations include, but are not limited to:

   - The assigned drafting team should consider whether VAR-002-WECC-2 (*Automatic Voltage Regulators (AVR)*) should be retired considering the most recent versions of VAR-001-4.1 and VAR-002-4 which require all AVRs to be in service and in voltage control mode unless exempted by the TOP based on identified criteria.
   - In VAR-001-4.1, Requirement R5 has no requirement to identify the "initial" status of the PSS. However, VAR-002-4 Requirement R3 requires the Generator Operator to notify the Transmission Operator of a power system stabilizer (PSS) status change. The initial status of the PSS should be clarified within the notification required by Requirement R5. The status of the PSS raises the question whether any of the VAR-501-WECC-2 (*Power System Stabilizer*), or any subsequent new version, PSS requirements should be established similar to AVR requirements for inclusion of the continent-wide standards. Industry comments affirm that it is not necessary to require notification of the initial state of the PSS as regional practices, interconnection agreements, and data specifications can address the initial state of the PSS.
   - The WECC variance E.A.18 is specific to external control loops to the manufacturer's AVR control loop. Due to the system configuration of the WECC, it was one of the earlier adopters of AVR and PSS controls. Due to the age of the controls or difficulty with setting reactive droop compensation on some older style controls, external loop controls were implemented from the plant control system. This can be done via DCS or SCADA. Variance E.A.18 requires that if external controls are used, that they do not affect the AVR's transient response during fault conditions. Industry comments did not reveal any reliability related need to address external control loops within the continent-wide Reliability Standard. Comments identified MOD-025 or MOD-026 as a more appropriate standard to address the

need to document and communicate the impact of external control loop actions on the AVR to the TOP.

6. Functions: Each function will be reviewed if affected.
   - Applicability 4.2.
     - Generator Operators within the Western Interconnection (for the WECC Variance)
7. Detailed Description:
   There are no specific issues identified; this is a mandated review.
8. Affected Reliability Principles: Which of the following reliability principles is MOST affected by this request? (select one)
   - **Reliability Principle 1** — *Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.*

Document Information

Specify the documents title, document number, and affected section regarding the request.

9. Document Title: Voltage and Reactive Control (with WECC Regional Variance)

Reference Uploads

Please reference or upload any affected Standards, Regional Business Practices, Criterion, Policies, White Papers, Technical Reports, or other relevant documents. If this request is based on a conflict of law, please include a copy of, or accessible reference to, the specific law or regulatory mandate in conflict.

10. Provide additional comments (if needed)

A. Introduction

1. Title: Voltage and Reactive Control

2. Number: VAR-001-4.2

3. Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. Applicability:

4.1. Transmission Operators

4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. Effective Date:

5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures[1]

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific

area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. Title: Voltage and Reactive Control

2. Number: VAR-001-5

3. Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. Applicability:

4.1. Transmission Operators

4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. Effective Date:

5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule, including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to, dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that, within 30 calendar days of a request by its Transmission Operator, it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that, within 30 calendar days of a request by its Generator Operator, it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata

1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	
5	TBD	Approved by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17

			were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific

area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-~~4.2~~5

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule, including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its ~~Area~~area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

~~**E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*~~

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to, dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

~~**E.A.16**~~**E.A.15** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that, within 30 calendar days of a request by its Transmission Operator, it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~**E.A.17**~~**E.A.16** Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that, within 30 calendar days of a request by its Generator Operator, it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~**E.A.18**~~**E.A.17** Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

~~**Measures**[1]~~

~~**M.E.A.13** Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.~~

~~**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.~~

~~**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.~~

~~**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.~~

~~**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~**M.E.A.18**~~**M.E.A.17** If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator ~~shall~~will have ~~and provide upon request,~~ evidence that it met the control loop specifications in sub-parts E.A.~~18~~17.1 through E.A.~~18~~17.2~~. Design~~, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation ~~are acceptable as evidence.~~

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Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
~~**E.A.15**~~	~~The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.~~

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.~~16~~15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.~~17~~16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator~~.~~ Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator~~.~~ Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.~~18~~17	N/A	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 through ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January~~,~~ 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

5	TBD	Approved by NERC Board of Trustees	1) In E.A.14 "Area" was changed to "area."; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing "shall" with "will"; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific

area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Attachment E
Project Roadmap
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Project Roadmap

Actions		Proposed Date
1.	SAR Filed	June 8, 2017
2.	Drafting Team solicitation	July 18, 2017
3.	WSC approved the SAR	July 6, 2017
4.	Notice of DT Solicitation–Augmented	August 21, 2017
5.	DT meeting	September 19, 2017
6.	Posting 1 Comments Open	September 25, 2017
7.	Posting 1 Comments Closed	November 10, 2017
8.	DT meeting–Subset	November 14, 2017
9.	DT meeting	December 13, 2017
10.	DT Meeting	December 20, 2017
11.	Posting 2 Comments Open	December 22, 2017
12.	Posting 2 Comments Closed	January 22, 2018
13.	DT Meeting	January 24, 2018
14.	WSC Approved for Ballot	March 6, 2018
15.	Ballot Pool Open	April 2, 2018
16.	Standard Briefing	April 13, 2018
17.	Ballot Pool Closed	April 16, 2018
18.	Ballot Open	April 18, 2018
19.	Ballot Closed	May 9, 2018
20.	WSC approves for WECC Board of Directors disposition	June 19, 2018
21.	WECC Board of Directors approval	June 20, 2018
22.	NERC Posting 45-day comment period–Open	June 22, 2018
23.	NERC Posting 45-day comment period–Closed	August 6, 2018
24.	NERC Board of Trustees approval	August 16, 2018
25.	FERC approval	TBD

Attachment F
Implementation Plan

WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Standards Authorization Request (SAR)

WECC-0128 VAR-001-4.2 SAR

Approvals Required

- WECC Board of Directors June 20, 2018
- NERC Board of Trustees August 16, 2018
- FERC Pending

Applicable Entities

4. Applicability:

4.1 Transmission Operators

4.2 Generator Operators within the Western Interconnection (for the WECC Variance)

Conforming Changes to Other Standards

This filing is the result of a five-year review mandated by the WECC Reliability Standards Development Procedures (Procedures).

Only the WECC Regional Variance (RV) E.A.15 is proposed for deletion.

No changes to other NERC Standards are required to implement the proposed deletion.

The content of the RV was originally proposed as a freestanding Regional Standard (proposed as VAR-001-WECC-1) but was "appropriately recast as a variance within the continent-wide Reliability Standard VAR-001-2 because it propose[d] to replace Requirements within the continent-wide Reliability Standard with region-specific requirements."[1] On June 20, 2013, the Federal Energy Regulatory Commission (FERC) approved the RV, thereby creating Version 3, with an effective date of January 1, 2014.[2] If approved, this filing would delete RV E.A.15 and update its nomenclature.[3]

[1] Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standard VAR-001-3 (Voltage and Reactive Control), March 11, 2013. See pages 5-6 for quotation. That filing contains the full historic development of the Version 3 and prior.

[2] The Project was originally developed as WECC-0046.

[3] Versions 4, 4.1, and 4.2 did not impact the RV.

Proposed Effective Date

Immediately upon receipt of applicable regulatory approval.

Justification

Because the reliability-related task required in RV E.A.15 is contained as a lesser included task of VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3, immediate implementation should have no impact on reliability, operations, or administration.

Consideration of Early Compliance

The drafting team foresees no concerns with early compliance.

Required Retirements

RV E.A.15 and its associated compliance and measurement elements should be retired.

No other retirements or modifications to other standards are needed.

Regional Reliability Standard Submittal
Request Attachment G

Region:	**Western Electricity Coordinating Council**
Regional Standard Number:	**VAR-001-5**[1]
Regional Standard Title:	**Voltage and Reactive Control with Regional Variance**
Date Submitted:	**DATE SUBMITTED TO NERC**
Regional Contact Name:	**Steven Rueckert**
Regional Contact Title:	**Director of Standards**
Regional Contact Telephone Number:	**(801) 883-6878**

Request (check all that apply):

- ☐ Retirement of WECC Regional Reliability Standard
- ☐ Interpret an Existing Standard
- ☐ Approval of a new standard
- ☒ Revision of an existing standard: VAR-001-4.2
- ☐ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors:

- ☒ Yes
- ☐ No

(If no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

June 20, 2018, Board of Directors / Board Resolution

[1] Numbering is subject to NERC assignment.

Resolved, that the Western Electricity Coordinating Council (WECC) Board of Directors (Board), acting upon the recommendation of the WECC Standards Committee (WSC) at the meeting of the Board on June 20, 2018 hereby approves the retirement of WECC Regional Variance E.A.15 in VAR-001-4.2, as described and attached hereunto.
[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:	In accordance with the WECC Reliability Standards Development Procedures (Procedures), the WECC Standards Committee shall ensure that each Regional Reliability Standard (RRS) is reviewed at least once every five years from the effective date of the most recent version of the RRS. This project is a result of the required five-year review. The WECC Regional Variance (RV) to VAR-001-4.2 was approved by FERC on June 13, 2013 (Docket No. RD13-6-000). The background, purpose, and stringency of the RV have not changed. Only the WECC RV was reviewed.[2]
Concise statement of the justification of the request:	The assigned drafting team reviewed the RV while considering NERC's recommendations included in the Periodic Review Recommendations for VAR-001-4.1 – Voltage and Reactive Control, May 19, 2017. After considering NERC's recommendations and comments received during two postings for comment, the drafting team made the following changes: • In E.A.14 "Area" was corrected to "area." • E.A.15 and associated elements were eliminated because the reliability-related task required in E.A.15 is contained as a lesser included task of

[2] The original Regional Variance was developed under WECC Tracking Number WECC-0046. This update was assigned WECC Tracking Number WECC-0128.

	VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3. • Measures were updated and relocated matching current NERC conventions, replacing “shall” with “will.” • Typographical errors in Violation Severity Level (VSL) Table for E.A.17 were corrected. • The format and numbering were updated.

Attachment H
Order 672 Criteria
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Not used

No revisions were made to any of the Continent-wide Requirements or the Regional Variances except the deletion of the E.A.15 Regional Variance.

E.A.15 was deleted. The Violation Severity Level (VSL) and Violation Risk Factor (VRF) were also deleted.

Only minor grammatical corrections and format changes to bring the document to the current drafting conventions.

Do not need to readdress the 672 Criteria as it was already addressed and approved when FERC approved the original WECC Regional Variances.

Attachment I
Drafting Team Roster

WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Below please find a biographical snapshot for the members of the WECC-0128 VAR-001-4.2, Voltage and Reactive Control Five-year Review Drafting Team.

Name	Background
Alex Chua Pacific Gas and Electric	• Electrical Engineer with 15 years of experience working in the transmission, distribution, and generation aspects of the company • The last four years have been focused on regulatory compliance for Generator Owner and Operators • Review and negotiate voltage schedules with transmission operators • Work with automation group on Automatic Voltage Regulator (AVR)/Power System Stabilizer (PSS) controls and generating notifications for status changes to our Transmission Operator (TOP) and Balancing Authority (BA) • Former WECC and NERC drafting team member
Shane Kronebusch L&S Electric	Mr. Kronebusch is the Lead Electrical Engineer and Subject Matter Expert for excitation systems, protection and hydro governors and unit controls for L&S Electric, Inc. He has over 27 years of experience in the utility industry. Prior to joining L&S Electric in 2010, Mr. Kronebusch's responsibilities included coordinating and preforming WECC testing of generation assets as an employee of BC Hydro Generation Engineering and Maintenance Services. He was responsible for commissioning both new and rehabilitated units ranging in size from 30MW to 500MW. Mr. Kronebusch was tasked as a subject matter expert for exciters and governors as part of the BC Hydro Equipment Health Rating program. Mr. Kronebusch first became involved with WECC testing after the July and August 1996 system disturbances that initiated the testing program. He has been a member of the WECC Control Work Group since 2006.
Mario Kiresich Southern California	Mr. Kiresich has been in the utility industry since 1997 and has held several positions: Call Center as a Customer Service Specialist, Groundman, Substation

Edison Grid Control	Electrician, Transmission Dispatcher, Procedure Administrator, Trainer, and Substation Supervisor. • 10 years in BES operations as Dispatcher, Compliance, Procedures, and Training • Transmission Operator and NERC Certified at the Reliability Coordinator (RC) level He has his Bachelor of Science in political science with a political communications emphasis and a minor in criminal justice from Chapman University. NERC Member as follows: 1) 2015-12 EOP-PRT (Observer), 2) 2017-03 FAC PRT (Member), 3) 2013-03 GMDSDT (Observer), 4) GMDTF (Member), 5) 2015-08 EOP SDT (Observer), and 6) 2015-07 COM-001 SDT (Vice Chair).
Alvin Pinkston	Mr. Pinkston has over 37 years of experience in the utility industry and has held several positions: Power Plant Manager for coal- and gas-fired power plants, Transmission / Distribution Control Center Manager, Trainer, Substation Relay Electrician, Instrument Electrician Technician. • 17 years nuclear plant operations as Work Control Supervisor, Electrical Maintenance Technician, and Supervisor • Transmission Operator and Control Center Manager and NERC Certified at the RC level • Five years as Transmission Operator Trainer • Subject Matter Expert for transmission operations and generation systems
Greg Anderson	Mr. Anderson is the Subject Matter Expert for generation and excitation systems for the Southern California Edison Company. He has over 33 years of experience in the utility industry, with responsibilities for coordinating WECC testing of generation assets. He has been a WECC participant since 1997 and a member of the Control Work Group since 2003.
Baj Agrawal Arizona Public Service Company	Mr. Agrawal has over 40 years of transmission and generation experience. He has been involved in generator excitation systems, power system stabilizers, and subsynchronous resonance. Mr. Agrawal has served on several NERC and WECC drafting teams including MOD-26, 27. He is currently serving on the NERC TPL-005-1 (Single Point of Failure)

	Drafting Team, the WECC Modeling Validation Work Group, the North American Transmission Forum, and the Modeling Practices Work Group Core team. Mr. Agrawal holds his Ph.D. in education.
James Wong	Mr. Wong joined the Bonneville Power Administration in 2009 where he serves as an operations planning engineer. He is experienced in thermal, voltage, and transient stability power system security studies for real-time and planning operations. Mr. Wong's work provides system operators real-time and planned procedures to enhance situational awareness for the dynamic conditions on the grid. As a graduate of Gonzaga University, Mr. Wong holds a Bachelor of Science in electrical engineering. Prior to working in the utility industry, Mr. Wong served his country in the United States Air Force and continues to serve in the Washington Air National Guard.[1]

[1] Although Mr. Wong participated in the drafting of the document, his assignment to the team did not take place until the November 15, 2017, WECC Standards Committee meeting.

Attachment J
Ballot Pool
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Ballot Pool

Title	Company	Sector	Vote	Comments	Created By
WECC-0128	Arizona Public Service Company	Transmission Owners	Yes		Michelle Amarantos
WECC-0128	Arizona Public Service Company	Electricity Brokers, Aggregators, and Marketers	Yes		Jonathan Aragon
WECC-0128	Arizona Public Service Company	Load-Serving Entities (LSE)	Yes		Vivian Vo
WECC-0128	Arizona Public Service Company	Electric Generators	Yes		Kelsi Rigby
WECC-0128	Black Hills Corporation	Electricity Brokers, Aggregators, and Marketers			Chad Thies
WECC-0128	Bonneville Power Administration	Load-Serving Entities (LSE)	Yes		Rebecca Berdahl
WECC-0128	Bonneville Power Administration	Transmission Owners	Yes		Kammy Rogers-Holliday
WECC-0128	Bonneville Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes		Andrew Meyers

Title	Company	Sector	Vote	Comments	Created By
WECC-0128	Bonneville Power Administration	Electric Generators	Yes		Scott Winner
WECC-0128	Idaho Power Company	Transmission Owners	Yes		Laura Nelson
WECC-0128	Idaho Power Company	Electric Generators	Yes		Laura Nelson
WECC-0128	Idaho Power Company	Load-Serving Entities (LSE)	Yes		Laura Nelson
WECC-0128	Northern California Power Agency	Electricity Brokers, Aggregators, and Marketers	Yes		Dennis Sismaet
WECC-0128	Platte River Power Authority	Transmission Owners	Yes		Jeff Landis
WECC-0128	Platte River Power Authority	Electric Generators	Yes		Tyson Archie
WECC-0128	Platte River Power Authority	Electricity Brokers, Aggregators, and Marketers	Yes		Sabrina Martz
WECC-0128	Platte River Power Authority	Load-Serving Entities (LSE)	Yes		Jeff Landis
WECC-0128	Public Service Company of Colorado (Xcel Energy)	Transmission Owners	Yes		Robert Staton

Title	Company	Sector	Vote	Comments	Created By
WECC-0128	Public Service Company of Colorado (Xcel Energy)	Electric Generators	Yes		Gerry Huitt
WECC-0128	Public Service Company of New Mexico	Electric Generators	Yes		Laurie Williams
WECC-0128	Public Service Company of New Mexico	Transmission Owners	Yes		Laurie Williams
WECC-0128	Public Service Company of New Mexico	Load-Serving Entities (LSE)	Yes		Laurie Williams
WECC-0128	Public Service Company of New Mexico	Electricity Brokers, Aggregators, and Marketers	Yes		Laurie Williams
WECC-0128	Puget Sound Energy, Inc.	Transmission Owners	Yes		Theresa Rakowsky
WECC-0128	Puget Sound Energy, Inc.	Load-Serving Entities (LSE)	Yes		Theresa Rakowsky
WECC-0128	Puget Sound Energy, Inc.	Electric Generators	Yes		Eleanor Ewry
WECC-0128	Puget Sound Energy, Inc.	Electric Generators			Theresa Rakowsky
WECC-0128	Salt River Project	Load-Serving Entities (LSE)	Yes		Robert Kondziolka

Title	Company	Sector	Vote	Comments	Created By
WECC-0128	Salt River Project	Electric Generators	Yes		Kevin Nielsen
WECC-0128	Seattle City Light	Transmission Dependent Utilities (TDU)	Yes		Hao Li
WECC-0128	Seattle City Light	Load-Serving Entities (LSE)	Yes		Charles Freeman
WECC-0128	Tacoma Power	Electric Generators	Yes		Karen Hedlund
WECC-0128	Tacoma Power	Transmission Dependent Utilities (TDU)	Yes		Chad Edinger
WECC-0128	Tacoma Power	Transmission Owners	Yes		Chad Edinger

Attachment K
Final Ballot Results
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Ballot Name: **VAR-001-4.2 Voltage and Reactive Control – WECC Regional Variance Five-year Review**

Overview: The following changes were made to the WECC Regional Variance; no changes were made to the body of the standard:

- Existing E.A.15 and associated elements were deleted because the task is contained in VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2., Part 2.3 as a lesser included task;
- In E.A.14 "Area" was changed to "area";
- Measures were updated and relocated matching current NERC conventions, replacing "shall" with "will";
- Typographical errors in the VSL Table for existing E.A.17 were corrected;
- The format was updated.

Ballot Pool Open:	04/02/2018	Ballot Opened:	04/18/2018
Ballot Pool Closed:	04/16/2018	Ballot Closed:	05/09/2018
Total Ballot Pool:	33	Total Votes:	32
Quorum:	96.97%	Weighted Votes:	100%

Ballot Results: Pass

Voting Sectors	Total in Ballot Pool	Votes Non-Abstain	Sector Weight	Yes Votes	Weighted Segment Vote	No Votes	Abstain	Total Votes for Quorum	Didn't Vote
1–Transmission Owners	8	8	0.8	8	80%	0	0	8	0
2–RTOs ISOs	0	0	0	0	00%	0	0		0
3–LSE	8	8	0.8	8	80%	0	0	8	0
4–Trans. Dep. Util.	2	2	0.2	2	20%	0	0	0	0
5–Elec. Gen.	9	9	.9	9	90%	0	0	0	0
6–Brokers, Aggr. & Markt.	6	5	0.5	5	50%	0	0	5	1
7–Large End User	0	0	0	0	00%	0	0	0	0
8–Small End User	0	0	0	0	00%	0	0	0	0
9–Gov./Reg.	0	0	0	0	00%	0	0	0	0
10–Reg. Entity	0	0	0	0	00%	0	0	0	0
Totals	33	32	3.2	32	100%	0	0	32	1

WECC
WESTERN ELECTRICITY COORDINATING COUNCIL
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

Attachment L
Minority Issues
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Following a ballot period from April 18 through May 9, 2018, the WECC Ballot Pool approved the requested changes to VAR-001-4.2 Voltage and Reactive Control–with WECC Regional Variance.

Development Phase Comments–Minority Opinion

Comment Response Forms and comments received during the development phase of this project are included with this filing as Attachment R1 and R2.

During the development phase, this project was posted twice for comment. The following minority opinions were received during the development phase:

- *There were no minority opinions. This project was approved with a 100 percent affirmative ballot.*

Ballot Phase Comments–Minority Opinion

The WECC Reliability Standards Development Procedures (Procedures) do not require a drafting team to respond to comments provided during the balloting phase of a project.

During the balloting phase, the following minority opinions were received:

- *There were no minority opinions. This project was approved with a 100 percent affirmative ballot.*

Attachment M
WECC Standards Committee Roster
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

The following individuals are those assigned to the WECC Standards Committee as of June 19, 2018.

Sector	Name	Organization
1 Transmission Owners	Sunitha Kothapalli	Puget Sound Energy
2 Regional Transmission Organizations (RTO) and Independent System Operators (ISO)	Robert Sullivan	California Independent System Operator
3 Load Serving Entities (LSE)	Cana Cabbell	Southern California Edison Company
4 Transmission Dependent Utilities (TDU)	Marty Hostler	Northern California Power Agency
5 Electric Generators	Gary Nolan	Arizona Publics Service Company
6 Electricity Brokers, Aggregators, and Marketers (BAM)	Joseph Tarantino	Sacramento Municipal Utility District
7 Large Electricity End Users	Caitlin Liotiris	Utah Association of Energy Users
8 Small Electricity Users	Crystal Musselman	Proven Compliance Solutions, Inc
9 Federal, State, and Provincial Regulatory or Other Government Entities	Davy Zhuang	British Columbia Utilities Commission
10 Regional Entities	Steven Rueckert	Western Electricity Coordinating Council
Chair	Michael Core	WECC Board of Directors

Attachment N1
Response to Comments WECC Posting 1
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Posting 1

The WECC-0128 VAR-001-4.2, Voltage and Reactive Control, Five-year Review Drafting Team (DT) thanks everyone who submitted comments on the proposed document. The scope of the review only includes the WECC Regional Variance (RV) appended to the NERC Standard.

Posting

The document was posted for a 45-day public comment period from September 25 through November 10, 2017.

On September 20, 2017, WECC distributed notice of the posting via the Standards Email List.

The DT asked stakeholders to provide feedback on the proposed document through a standardized electronic template. WECC received comments from three entities as shown in the following table.

Location of Comments

All comments received on the document can be viewed in their original format on the WECC-0128 project page under the "Submit and Review Comments" accordion.

Changes in Response to Comment

After consideration of comments received and further DT discussions held on December 13 and December 20, 2017, the DT concluded that only RV E.A.15 should be deleted. Deletion is appropriate because the task is contained in VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2., Part 2.3 as a lesser included task.

Rationale for Deletion

In VAR-001-4.2, Voltage and Reactive Power, the Transmission Operator issues to the Generator Operator any one of three types of voltage schedules.[1] The voltage schedule must contain any one of four reference points.[2] If the Generator Operator is not monitoring the voltage at the location specified in its voltage schedule, the Generator Operator must have a methodology for converting the voltage schedule to the voltage point being monitored by the Generator Operator.[3] The Generator Operator

[1] VAR-001-4.2, Voltage and Reactive Control, Regional Variance (RV) E.A.13
[2] RV. E.A.14
[3] VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2., Part 2.3

then converts the schedule into the voltage set point for the generator excitation system[4] and maintains the schedule, unless otherwise exempted.[5]

Restated, VAR-002-4.1 requires the Generator Operator to have a conversion methodology and VAR-001-4.2 requires the Generator Operator to use the methodology. If the Generator Operator does not have a conversion methodology as required in VAR-002-4.1, it is impossible for the Generator Operator to use that methodology as required in VAR-001-4.2. As a result, the single act of omission in VAR-002-4.1 triggers a second violation in the RV of VAR-001-4.2.

By deleting E.A.15, duplicative violation based on a single omission is avoided.

Deletion of E.A.15 would have no impact on reliability because the reliability-related task is contained in VAR-002-4.1, Requirement R2 wherein the Generator Operator is required to *operate* to the schedule. Operating to that schedule cannot take place without converting the schedule (where applicable); therefore, the conversion mandate of E.A.15 is a lesser included step implied and required in VAR-002-4.1, Requirement R2. Because it is a lesser included step, it is redundant and can be deleted from the RV without negative impact to reliability.

Other Considerations

The team opted to retain E.A.13 after concluding that although portions of the requirement could default back to Requirement R5, the operational value would be di minimus and parsing the pericope would only add ambiguity.

The team opted to retain E.A.14 noting that it adds greater granularity than Requirement R5 and enhances operation by allowing for greater flexibility.

The team opted to retain E.A.16 noting that its content is not covered elsewhere.

The team opted to retain E.A.17 noting its provision for bilateral communication is not otherwise addressed elsewhere.

The team considered deletion of E.A.18 in favor of MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions, Requirement R2. However, the MOD Standard does not engage the same applicable entities nor provide for agreement between the affected parties.

Consideration was given to reinstatement of Requirements R4 and R5 coupled with the elimination of corresponding portions of the RV; however, the DT concluded the original intent of the document still holds.[6] If Requirements R4 and R5 were reinstated, the Transmission Operator could choose to supply

[4] RV E.A.15

[5] VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2

[6] "The Regional Variance requires conversion of a reactive support schedule provided by a Transmission Operator to an equivalent voltage schedule, thereby permitting operation of generators in voltage control mode without the additional responsibility of manually revising the voltage west-point to also maintain a required reactive schedule having an automatic

the Generator Operator with a reactive power schedule in lieu of voltage schedules. As a result, the Generator Operator would be required to perform continuous manual adjustments to maintain a reactive power schedule.

Minority View.

There was no minority view.

Effective Date and Implementation Plan

The WECC Reliability Standards Development Procedures (Procedures) require that an implementation plan be posted with at least one posting of the project. The Effective Date is proposed as immediately on receipt of regulatory approval. An immediate effective date is appropriate because the task being eliminated is already being performed in compliance with VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2., Part 2.3. The Implementation Plan will be posted with Posting 2.

Action Plan

On December 20, 2017, the WECC-0128 VAR-001-4.2, Voltage and Reactive Control, Five-year Review Drafting Team (DT) agreed by majority vote to post Posting 2 of the project for a 30-day comment period. Posting 2 will include an implementation plan.

The posting period will open December 22, 2017 and close January 22, 2018. The drafting team will meet on January 24 and 31, 2018 from 10:00 a.m. to 12:00 p.m., as needed, to discuss disposition of the project.

Comments can be submitted using the green survey buttons located on the Submit and Review Comments accordion of the WECC-0128 project page.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant. In addition, the WECC Reliability Standards Appeals Process can be found in the Reliability Standards Development Procedures.

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voltage regulation in service and in voltage control mode was identify using disturbance analysis as essential for the reliability of the Bulk Electric System in the WECC region die to western transmission configurations." Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standard VAR-001-3 (Voltage and Reactive Control), March 11, 2013. See pages 2-3 for quotation. That filing contains the full historic development of the Version 3 and prior.

Comment Report Form for WECC-0128

WECC Standards Comment Table

Commenter		Organization
1	Marty Hostler	Northern California Power Agency (NCPA)
2	William Franklin	Public Service Company of Colorado (PSCo)
3	Neil Swearingen	Salt River Project (SRP)

Comment Report Form for WECC-0128

Index to Questions, Comments, and Responses

Question

1. This project covers the WECC Variance attached to VAR-001-4.1 Voltage and Reactive Control. Currently, the variance renders WECC exempt from Requirement R4. The WECC-0128 drafting team is suggesting that Requirement R4 be reinstated and become applicable to WECC. The drafting team is suggesting reinstatement of Requirement R4 because: 1) revitalization does not take away reliability but does add flexibility, and 2) for some small generators, operation without Automatic Voltage Regulation (AVR) may be the best reliability choice. Should the exemption from Requirement R4 be deleted?

1a. If you answered no to Question 2, please explain your answer.

2. The drafting team is suggesting that Variance Requirements E.A.15 through E.A.17 be deleted because the reliability-related content is addressed in VAR-002-4, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2. Should Variance requirements E.A.15 through E.A.18 be deleted?

2a. If you answered no to Questions 3, please explain your answer.

3. The drafting team is suggesting that Variance Requirements E.A.18 be deleted because the reliability-related content is addressed in MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions, Requirement R2 (see also the Purpose statement for MOD-026). Should Variance requirement E.A.18 be deleted?

3a. If you answered no to Questions 4, please explain your answer.

4. The drafting team welcomes comments on all other aspects of the Variance. Comments regarding changes to the supporting body of the standard will not be addressed.

Comment Report Form for WECC-0128

1. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	Yes
The drafting team thanks NCPA for its continued involvement in the standards development process.	
PSCo	Yes
The drafting team thanks PSCo for its continued involvement in the standards development process.	
SRP	Yes
The drafting team thanks SRP for its continued involvement in the standards development process.	

1a. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	No response.
PSCo	No response
SRP	No response

2. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	Yes
The drafting team thanks NCPA for its continued involvement in the standards development process.	
PSCo	Yes
The drafting team thanks PSCo for its continued involvement in the standards development process.	
SRP	Yes
The drafting team thanks SRP for its continued involvement in the standards development process.	

2a. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	No response
PSCo	No response
SRP	No response

3. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	Yes
The drafting team thanks NCPA for its continued involvement in the standards development process.	
PSCo	Yes
The drafting team thanks PSCo for its continued involvement in the standards development process.	
SRP	Yes
The drafting team thanks SRP for its continued involvement in the standards development process.	

3a. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	No response
PSCo	No response
SRP	No response

4. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
NCPA	Looks good
The drafting team thanks NCPA for its continued involvement in the standards development process.	
PSCo	No comment
The drafting team thanks PSCo for its continued involvement in the standards development process.	
SRP	SRP agrees with the proposed changes as they add flexibility to exempt generators and remove the redundancy of regional variances that are already addressed in other Standards
The drafting team thanks SRP for its continued involvement in the standards development process.	

Attachment N2
Response to Comments WECC Posting 2
WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Posting 2

The WECC-0128 VAR-001-4.2, Voltage and Reactive Control, Five-year Review Drafting Team (DT) thanks everyone who submitted comments on the proposed document. The scope of the review only includes the WECC Regional Variance (RV) appended to the NERC Standard.

Posting

The document was posted for a 30-day public comment period from December 22, 2017, through January 22, 2018.

On December 20, 2017, WECC distributed notice of the posting via the Standards Email List.

The DT asked stakeholders to give feedback on the proposed document through a standardized electronic template. WECC received comments from two entities as shown in the following table.

Location of Comments

All comments received on the document can be viewed in their original format on the WECC-0128 project page under the "Submit and Review Comments" accordion.

Changes in Response to Comment

The drafting will update the numbering and references. A second look at the project will also take place once the near-final project is presented for technical writing.

Other Considerations

None

Minority View.

There was no minority view.

Effective Date and Implementation Plan

The WECC Reliability Standards Development Procedures (Procedures) require that an implementation plan be posted with at least one posting of the project. The Effective Date is proposed as immediately on receipt of regulatory approval. An immediate effective date is appropriate because the task being eliminated is already being performed in compliance with VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2., Part 2.3. The Implementation Plan was posted with Posting 1.

Action Plan

On January 24, 2018, the WECC-0128 Drafting Team agreed by a majority of those present to forward the project to the WECC Standards Committee (WSC) with a request for ballot.

The request is targeted for the March 6, 2018, WSC agenda.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant. In addition, the WECC Reliability Standards Appeals Process can be found in the Reliability Standards Development Procedures.

WECC Standards Comment Table

Commenter		Organization
1	Twila Hofer	Tacoma Power
2	Michelle Amarantos on Behalf of Todd Komaromy	Arizona Publics Service Company

Index to Questions, Comments, and Responses

Question

1. The drafting team welcomes comments all aspects of the Regional Variance. The scope of the project does not allow for changes to the body of the underlying standard.

1. Response Summary

Summary Consideration:	See summary in the preamble of this document.		
Commenter / Comment			**Response**
Tacoma Power			M.E.A.17 – Revise reference to E.A.18.1 and E.A.18.2 to E.A.17.1 and E.A.17.2
The drafting team appreciates Tacoma's continued involvement in the standards development process. Corrections to the references were made.			
APS			APS is supportive of the changes being recommended by the SDT, including the deletion of the requirement E.A.15.
The drafting team appreciates APS's continued involvement in the standards development process.			

Regional Reliability Standards Under Development

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Western Electricity Coordinating Council (WECC)				
VAR-001-5 (Revisions to WECC Variance)	Voltage and Reactive Control	Standard Under Development	6/22/18 - 8/6/18	Info **(1)** VAR-001-5 Clean **(2)** | Redline **(3)** Unofficial Comment Form (Word) **(4)** Submit Comments Comment Received **(5)** Consideration of Comments **(6)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

VAR-001-5 | WECC Variance

Comment Period Open through August 6, 2018

Now Available

Western Electricity Coordinating Council (WECC) requested that NERC post **VAR-001-5 - Voltage and Reactive Control** for industry review and comment in accordance with the NERC Rules of Procedure.

Commenting

Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Nasheema Santos. The form must be submitted by **8 p.m. Eastern, Monday, August 6, 2018.** An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development page**.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties using the electronic form, contact Nasheema Santos. The form must be submitted by **8 p.m. Eastern, Monday, August 6, 2018.** An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development page.

Regional Reliability Standards Development Process

Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

Background

WECC requested that NERC post **VAR-001-5 - Voltage and Reactive Control** for industry review and comment in accordance with the NERC Rules of Procedure.

The drafting team made the following changes:

- In E.A.14 "Area" was corrected to "area".
- E.A.15 and associated elements were eliminated because the reliability-related task required in E.A.15 is contained as a lesser included task of VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3.
- Measures were updated and relocated matching current NERC conventions, and "shall" was replaced with "will".
- Typographical errors in VSL Table for E.A.17 were corrected.

- The format and numbering were updated.

The standard was posted for comment twice, the most recent period being from December 22, 2017 – January 22, 2018, and the comments received can be viewed here.

For more information or assistance, contact Reliability Standards Analyst, Nasheema Santos (via email) or at (404) 446-2564.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

A. Introduction

1. Title: Voltage and Reactive Control

2. Number: VAR-001-5

3. Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. Applicability:

4.1. Transmission Operators

4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. Effective Date:

5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
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5	TBD	Approved by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15

			and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific

area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-~~4.2~~5

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its ~~Area~~area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

~~**E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*~~

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

~~**E.A.16**~~**E.A.15** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~E.A.17~~E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

~~E.A.18~~E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

~~**Measures**[1]~~

~~**M.E.A.13** Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.~~

~~**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.~~

~~**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.~~

~~**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.~~

~~**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~**M.E.A.18**~~**M.E.A.17** If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator ~~shall~~will have ~~and provide upon request,~~ evidence that it met the control loop specifications in sub-parts E.A.~~18~~17.1 through E.A.~~18~~17.2~~. Design~~, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation~~. are acceptable as evidence.~~

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
~~**E.A.15**~~	~~The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.~~	~~The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.~~

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.~~16~~15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.~~17~~16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.~~18~~17	N/A	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in ~~EA18~~E.A.17.1 through ~~EA18~~E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

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Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific

area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Regional Reliability Standard
VAR-001-5 | WECC Variance

DO NOT use this form for submitting comments. Use the electronic form to submit comments on Regional Reliability Standard **VAR-001-5 Voltage and Reactive Control (WECC Variance)**. Comments must be submitted by **8 p.m. Eastern, Monday, August 6, 2018.**

The Regional Reliability Standards Under Development page contains documents and information about this project. If you have questions, contact Nasheema Santos (via email).

Background Information

Western Electricity Coordinating Council (WECC) requested that NERC post the revised WECC Variance in VAR-001-5 Voltage and Reactive Control for industry review and comment in accordance with the NERC Rules of Procedure.

The drafting team made the following changes:

- In E.A.14 "Area" was corrected to "area".
- E.A.15 and associated elements were eliminated because the reliability-related task required in E.A.15 is contained as a lesser included task of VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3.
- Measures were updated and relocated matching current NERC conventions; the term "shall" was replaced with "will".
- Typographical errors in VSL Table for E.A.17 were corrected.
- The format and numbering were updated.

The standard was posted twice for comment, most recently form December 22, 2017 – January 22, 2018, and the comments received can be viewed here.

Any variance from a NERC Reliability Standard Requirement that is proposed to apply to responsible entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved regional Reliability Standards development procedure. While an Interconnection-wide Variance may be developed through the associated Regional Entity standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting team 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 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.

NERC is publicly noticing and requesting comment on the proposed WECC Variance. Comments shall be permitted only on the following criteria (technical aspects of the Variance are vetted through the regional standards development process):

Unfair or Closed Process – The Variance was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections – The Variance would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard – The Variance fails to provide a level of reliability of the bulk power system such that the rVariance would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection – The rVariance would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

Questions

1. **Do you agree the proposed standard/variance was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No
   Comments:

2. **Does the proposed standard/variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No
   Comments:

3. **Does the proposed standard/variance pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No
   Comments:

4. **Does the proposed standard/variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes
   ☐ No
   Comments:

5. **Does the proposed regional reliability standard/variance meet at least one of the following criteria?**

   - **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**
   - **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

   ☐ Yes
   ☐ No
   Comments:

Comment Report

Project Name:	Regional Reliability Standard | VAR-001-5 (WECC Variance)
Comment Period Start Date:	6/22/2018
Comment Period End Date:	8/6/2018
Associated Ballots:	

There were 8 sets of responses, including comments from approximately 8 different people from approximately 7 companies representing 4 of the Industry Segments as shown in the table on the following pages.

*Note: Comment report was corrected following the posting of the Consideration of Comments.

Questions

1. Do you agree the proposed standard/variance was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

2. Does the proposed standard/variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

3. Does the proposed standard/variance pose a serious and substantial threat to public health, safety, welfare, or national security?

4. Does the proposed standard/variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

5. Does the proposed regional reliability standard/variance meet at least one of the following criteria?

- **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**
- **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region

1. Do you agree the proposed standard/variance was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
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	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Does the proposed standard/variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
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	

3. Does the proposed standard/variance pose a serious and substantial threat to public health, safety, welfare, or national security?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
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	

4. Does the proposed standard/variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
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	

5. Does the proposed regional reliability standard/variance meet at least one of the following criteria?

- **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**
- **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

- **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**

Yes the variance has more specific criteria for voltage schedules and generator reference points.

- **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**

Yes in that the variance doesn't have allowance for exemption criteria and includes transmission operator requirements for submitting data.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
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	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	Regional Reliability Standard | VAR-001-5 (WECC Variance)
Comment Period Start Date:	6/22/2018
Comment Period End Date:	8/6/2018
Associated Ballots:	

There were 8 sets of responses, including comments from approximately 8 different people from approximately 7 companies representing 4 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 Senior Director of Standards and Education, Howard Gugel (via email) or at (404) 446-9693.

If you have any questions regarding the WECC Reliability Standards Development Procedures or this project, please contact WECC Consultant, W. Shannon Black at (503) 307-5782.

Questions

1. Do you agree the proposed standard/variance was developed in a fair and open process, using the associated Regional Reliability Standa Development Procedure?

2. Does the proposed standard/variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

3. Does the proposed standard/variance pose a serious and substantial threat to public health, safety, welfare, or national security?

4. Does the proposed standard/variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

5. Does the proposed regional reliability standard/variance meet at least one of the following criteria?

- The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.
- The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.
- The proposed regional difference is necessitated by a physical difference in the bulk power system.

WECC Summary Response:

The WECC-0128 VAR-001-5, Voltage and Reactive Control – WECC Regional Variance Drafting Team would like to thank everyone that participated in the standards development process. The value of each standard is enriched as the depth of participation increases.

1. Do you agree the proposed standard/variance was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
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	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Does the proposed standard/variance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
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
In the absence of additional information from Black Hills, the project drafting team is unable to provide additional insights. WECC does note that the ballot passed at 100% at WECC.

3. Does the proposed standard/variance pose a serious and substantial threat to public health, safety, welfare, or national security?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
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
In the absence of additional information from Black Hills, the project drafting team is unable to provide additional insights. WECC does note that the ballot passed at 100% at WECC.

4. Does the proposed standard/variance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
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
In the absence of additional information from Black Hills, the project drafting team is unable to provide additional insights. WECC does note that the ballot passed at 100% at WECC.

5. Does the proposed regional reliability standard/variance meet at least one of the following criteria?

- **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**
- **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

- **The proposed standard/variance has more specific criteria for the same requirements covered in a continent-wide standard.**

Yes the variance has more specific criteria for voltage schedules and generator reference points.

- **The proposed standard/variance has requirements that are not included in the corresponding continent-wide reliability standard.**

Yes in that the variance doesn't have allowance for exemption criteria and includes transmission operator requirements for submitting data.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	

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	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Exhibit C

Standard Drafting Team Roster for Project WECC-0128, VAR-001-4.1, Voltage and Reactive Control – WECC Regional Variance, Five-Year Review

Drafting Team Roster

WECC-0128
VAR-001-4.2 Voltage and Reactive Control
Regional Variance Five-year Review

Below please find a biographical snapshot for the members of the WECC-0128 VAR-001-4.2, Voltage and Reactive Control Five-year Review Drafting Team.

Name	Background
Alex Chua Pacific Gas and Electric	• Electrical Engineer with 15 years of experience working in the transmission, distribution, and generation aspects of the company • The last four years have been focused on regulatory compliance for Generator Owner and Operators • Review and negotiate voltage schedules with transmission operators • Work with automation group on Automatic Voltage Regulator (AVR)/Power System Stabilizer (PSS) controls and generating notifications for status changes to our Transmission Operator (TOP) and Balancing Authority (BA) • Former WECC and NERC drafting team member
Shane Kronebusch L&S Electric	Mr. Kronebusch is the Lead Electrical Engineer and Subject Matter Expert for excitation systems, protection and hydro governors and unit controls for L&S Electric, Inc. He has over 27 years of experience in the utility industry. Prior to joining L&S Electric in 2010, Mr. Kronebusch's responsibilities included coordinating and preforming WECC testing of generation assets as an employee of BC Hydro Generation Engineering and Maintenance Services. He was responsible for commissioning both new and rehabilitated units ranging in size from 30MW to 500MW. Mr. Kronebusch was tasked as a subject matter expert for exciters and governors as part of the BC Hydro Equipment Health Rating program. Mr. Kronebusch first became involved with WECC testing after the July and August 1996 system disturbances that initiated the testing program. He has been a member of the WECC Control Work Group since 2006.
Mario Kiresich Southern California	Mr. Kiresich has been in the utility industry since 1997 and has held several positions: Call Center as a Customer Service Specialist, Groundman, Substation

Edison Grid Control	Electrician, Transmission Dispatcher, Procedure Administrator, Trainer, and Substation Supervisor. • 10 years in BES operations as Dispatcher, Compliance, Procedures, and Training • Transmission Operator and NERC Certified at the Reliability Coordinator (RC) level He has his Bachelor of Science in political science with a political communications emphasis and a minor in criminal justice from Chapman University. NERC Member as follows: 1) 2015-12 EOP-PRT (Observer), 2) 2017-03 FAC PRT (Member), 3) 2013-03 GMDSDT (Observer), 4) GMDTF (Member), 5) 2015-08 EOP SDT (Observer), and 6) 2015-07 COM-001 SDT (Vice Chair).
Alvin Pinkston	Mr. Pinkston has over 37 years of experience in the utility industry and has held several positions: Power Plant Manager for coal- and gas-fired power plants, Transmission / Distribution Control Center Manager, Trainer, Substation Relay Electrician, Instrument Electrician Technician. • 17 years nuclear plant operations as Work Control Supervisor, Electrical Maintenance Technician, and Supervisor • Transmission Operator and Control Center Manager and NERC Certified at the RC level • Five years as Transmission Operator Trainer • Subject Matter Expert for transmission operations and generation systems
Greg Anderson	Mr. Anderson is the Subject Matter Expert for generation and excitation systems for the Southern California Edison Company. He has over 33 years of experience in the utility industry, with responsibilities for coordinating WECC testing of generation assets. He has been a WECC participant since 1997 and a member of the Control Work Group since 2003.
Baj Agrawal Arizona Public Service Company	Mr. Agrawal has over 40 years of transmission and generation experience. He has been involved in generator excitation systems, power system stabilizers, and subsynchronous resonance. Mr. Agrawal has served on several NERC and WECC drafting teams including MOD-26, 27. He is currently serving on the NERC TPL-005-1 (Single Point of Failure)

	Drafting Team, the WECC Modeling Validation Work Group, the North American Transmission Forum, and the Modeling Practices Work Group Core team. Mr. Agrawal holds his Ph.D. in education.
James Wong	Mr. Wong joined the Bonneville Power Administration in 2009 where he serves as an operations planning engineer. He is experienced in thermal, voltage, and transient stability power system security studies for real-time and planning operations. Mr. Wong's work provides system operators real-time and planned procedures to enhance situational awareness for the dynamic conditions on the grid. As a graduate of Gonzaga University, Mr. Wong holds a Bachelor of Science in electrical engineering. Prior to working in the utility industry, Mr. Wong served his country in the United States Air Force and continues to serve in the Washington Air National Guard.[1]

[1] Although Mr. Wong participated in the drafting of the document, his assignment to the team did not take place until the November 15, 2017, WECC Standards Committee meeting.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-7-000

September 25, 2018

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard BAL-002-3

Dear Mr. Elstein:

On August 17, 2018, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of proposed Reliability Standard BAL-002-3 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event) and the retirement of currently-effective Reliability Standard BAL-002-2. NERC submitted proposed Reliability Standard BAL-002-3 in response to the Commission's directive in Order No. 835 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.[1]

NERC's filing was noticed on August 17, 2018, with interventions, comments and protests due on or before September 10, 2018. No comments were received.

[1] *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard,* Order No. 835, 158 FERC ¶ 61,030, at P 37 (2017).

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2018), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2018).

Sincerely,

David Ortiz, Acting Director
Office of Electric Reliability

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR18-6-000

Issued: September 25, 2018

Owen E. MacBride
Schiff Hardin LLP
233 South Wacker Drive, Suite 7100
Chicago, IL 60606

Reference: Report of Comparisons of Budgeted to Actual Costs for 2017

On May 30, 2018, North American Electric Reliability Corporation (NERC) submitted a report of comparisons of budgeted to actual costs for 2017 for NERC and the Regional Entities.

Notice of this filing was issued on May 30, 2018, with protests and interventions due on or before June 20, 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.

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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

20180906-3015 FERC PDF (Unofficial) 09/06/2018

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR18-8-000

September 6, 2018

North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600
Atlanta, GA 30326

Attention: Nina H. Jenkins-Johnston
Senior Counsel, North American Electric Reliability Corporation

Reference: Amendments to Midwest Reliability Organization Bylaws

Dear Ms. Jenkins-Johnston:

On June 4, 2018, North American Electric Reliability Corporation submitted amendments to the Midwest Reliability Organization (MRO) Bylaws to add two Regional Director positions and increase the number of Independent Director positions on MRO's Board of Directors.

Notice of this filing was issued on June 5, 2018, with protests and interventions due on or before June 25, 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

20180906-3015 FERC PDF (Unofficial) 09/06/2018

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

20180906-3015 FERC PDF (Unofficial) 09/06/2018

Document Content(s)

RR18-8-000.DOCX.....1-2

20180925-3009 FERC PDF (Unofficial) 09/25/2018

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR18-7-000

Issued: September 25, 2018

Nina H. Jenkins-Johnston
North American Electric Reliability Corporation
3353 Peachtree Road NE,
North Tower, Suite 600
Atlanta, GA 30326

Reference: Amended North American Electric Reliability Corporation Bylaws

On June 4, 2018, North American Electric Reliability Corporation (NERC) submitted a petition for approval of amendments to the Bylaws of NERC to reduce the five-day prior notice requirement for Board of Trustees meetings held in closed session to a 24-hour prior notice period. NERC states that this will permit the Board of Trustees to address matters that may be considered during a closed session in a more timely manner when necessary.

Notice of this filing was issued on June 5, 2018, with protests and interventions due on or before June 25, 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, effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(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

20180925-3009 FERC PDF (Unofficial) 09/25/2018

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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

Document Content(s)

RR18-7-000.DOCX.....1-2

20180905-3011 FERC PDF (Unofficial) 09/05/2018

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-1-000

September 5, 2018

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Retirement of Regional Reliability Standard VAR-002-WECC-2

Dear Mr. Elstein:

On March 7, 2018, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of retirement of regional Reliability Standard VAR-002-WECC-2 (Automatic Voltage Regulators). NERC and WECC requested approval of the retirement effective date as of the date of regulatory approval. NERC and WECC state that experience with regional Reliability Standard VAR-002-WECC-2 has shown that the reliability-related issues addressed in the regional Reliability Standard are adequately addressed by the continent-wide Voltage and Reactive (VAR) Reliability Standards and that retention of the regional Reliability Standard would not provide additional benefits for reliability.[1]

NERC's filing was noticed on March 12, 2018, with interventions, comments and protests due on or before April 11, 2018. Southern California Edison filed a timely motion to intervene, raising no issues.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017),

[1] Petition at 1.

20180905-3011 FERC PDF (Unofficial) 09/05/2018

effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

David Ortiz, Acting Director
Office of Electric Reliability

Document Content(s)

RD18-1-000.DOCX.....1-2

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

September 13, 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:	September 20, 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.

1047th - MEETING

OPEN MEETING

September 20, 2018

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD18-2-000	Customer Matters, Reliability, Security and Market Operations
A-2	AD18-1-000	Agency Administrative Matters
A-3	AD18-17-000	Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities
		ELECTRIC
E-1	EL18-152-000	Louisiana Public Service Commission v. System Energy Resources, Inc. and Entergy Services, Inc.
E-2	EL16-120-002 ER17-2153-002 ER18-1153-000	New England Power Generators Association, Inc. v. ISO New England Inc. ISO New England. Inc. ISO New England, Inc.
E-3	ER10-1791-004	Midwest Independent Transmission System Operator, Inc.
E-4	ER17-2073-001	PJM Interconnection, L.L.C.
E-5	ER17-2267-001	PJM Interconnection, L.L.C.
E-6	ER14-2154-006 ER15-277-005 (consolidated)	Midcontinent Independent System Operator, Inc.
E-7	EL17-44-000	Northern States Power Company, Minnesota
E-8	EL18-145-000	Tilton Energy LLC v. PJM Interconnection, L.L.C.
E-9	ER14-1409-000	ISO New England Inc.
E-10	EL18-131-000	Nevada Hydro Company, Inc.
E-11	ER17-1750-002	Pacific Gas and Electric Company

GAS

G-1	OMITTED	
G-2	OMITTED	
G-3	OR18-7-000	Epsilon Trading, LLC, Chevron Products Company, and Valero Marketing and Supply Company v. Colonial Pipeline Company
	OR18-12-000	BP Products North America, Inc., Trafigura Trading LLC, and TCPU, Inc. v. Colonial Pipeline Company
	OR18-17-000	TransMontaigne Product Services LLC v. Colonial Pipeline Company
	OR18-21-000 (consolidated)	CITGO Petroleum Corporation v. Colonial Pipeline Company

HYDRO

H-1	EL18-56-000 P-12966-005	Utah Board of Water Resources
H-2	P-2611-087	Hydro-Kennebec LLC

CERTIFICATES

C-1	CP09-465-002	Northern Natural Gas Company
C-2	CP17-219-000	Southern Star Central Gas Pipeline, Inc.

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.

September 2018
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its September 20, 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.

FERC establishes hearing and settlement procedures

E-1, *Louisiana Public Service Commission v. System Energy Resources, Inc. and Entergy Services, Inc.*, Docket No. EL18-152-000. The order establishes hearing and settlement procedures on the complaint that the Louisiana Public Service Commission (Louisiana Commission) filed against System Energy Resources, Inc. (SERI) and Entergy Services, Inc. (Entergy). The Louisiana Commission alleges that SERI and Entergy violated the filed-rate doctrine and FERC's ratemaking and accounting requirements in billing the costs of the Grand Gulf Nuclear Power Station's sale-leaseback renewals through the formula rate that is part of a Unit Power Sales Agreement between SERI and Entergy Arkansas, Inc., Entergy Louisiana L.L.C., Entergy Mississippi, Inc., and Entergy New Orleans, Inc.

FERC denies clarification, accepts compliance filing

E-2, *ISO New England Inc.*, Docket No. EL16-120-002, *et al.* The order denies a request for clarification of a prior Commission order that accepted a settlement agreement related to ISO New England's (ISO-NE) Peak Energy Rent (PER) provisions in its tariff. In approving the settlement, the Commission directed ISO-NE to submit tariff revisions to the methodology for calculating PER Adjustments contained in the ISO-NE tariff for the time period identified in the settlement. The order also accepts ISO-NE's compliance filing.

FERC denies requests for rehearing; grants, in part, requests for clarification

E-3, *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER10-1791-004. The order denies the requests for rehearing and grants, in part, the requests for clarification of the underlying order in which the Commission responded to the U.S. Court of Appeals for the Seventh Circuit's remand of the Commission's orders addressing the Midwest Independent Transmission System Operator, Inc.'s Multi Value Projects.

FERC denies rehearing

E-4, *PJM Interconnection, L.L.C.*, Docket No. ER17-2073-001. The order denies a request filed by Linden VFT, LLC for rehearing of the Commission's September 8, 2017 order rejecting an unexecuted, amended Interconnection Service Agreement (Amended ISA) filed under section 205 of the Federal Power Act by PJM. The proposed Amended ISA modified Service Agreement No. 2536 whose parties are PJM, Hudson Transmission Partners, LLC, and Public Service Electric and Gas Company.

FERC denies rehearing

E-5, *PJM Interconnection, L.L.C.*, Docket No. ER17-2267-001. The order denies a request filed by Linden VFT, LLC (Linden) for rehearing of the Commission's October 5, 2017 order rejecting an unexecuted, amended Interconnection Service Agreement (Amended ISA) filed under section 205 of the Federal Power Act by PJM. The proposed Amended ISA modified Service Agreement No. 3579, whose parties were PJM, Linden, and Public Service Electric and Gas Company.

FERC affirms an Initial Decision

E-6, *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER14-2154-006 and ER15-277-005. The order affirms the Presiding Judge's findings that Rochester Public Utilities Board's (RPU) annual transmission revenue requirement for the Hampton-to-North Rochester 345-kV transmission line should be recovered through transmission rates for MISO Pricing Zone 16. The order also affirms the Presiding Judge's findings that MISO possessed the filing rights under the MISO Transmission Owners Agreement and section 205 of the Federal Power Act to make the filing to add RPU to Pricing Zone 16.

FERC terminates section 206 proceeding

E-7, *Northern States Power Company, Minnesota*, Docket No. EL17-44-000. The order finds that the Midcontinent Independent System Operator, Inc. (MISO) Pricing Zone 16 Joint Pricing Zone Revenue Allocation Agreement, as revised to conditionally add the

Rochester Public Utilities Board (RPU) as an Addendum Party, is just and reasonable and not unduly discriminatory or preferential. In addition, the order finds that it has not been shown in the proceeding that further revisions to the MISO tariff or the MISO Transmission Owners Agreement are necessary at this time to prevent denial, through exclusion from a Joint Pricing Zone agreement, of recovery of Commission-accepted transmission rates, and terminates the section 206 proceeding.

FERC establishes paper hearing procedures

E-8, *Tilton Energy LLC v. PJM Interconnection, L.L.C.*, Docket No. EL18-145-000. This order establishes paper hearing procedures to examine issues raised in a complaint filed by Tilton against PJM. In the complaint, Tilton alleges that PJM wrongly determined that a Tilton facility's pseudo-tie from the Midcontinent Independent System Operator, Inc. Balancing Authority Area (BAA) into the PJM BAA does not pass the market-to-market flowgate test set forth in the PJM Open Access Transmission Tariff at Attachment DD, section 5.5A(b)(i)(B). The order also establishes a refund effective date.

FERC finds amended protest filing untimely

E-9, *ISO New England Inc.*, Docket No. ER14-1409-000. This order dismisses an amended protest filed in this docket on February 10, 2015 by the Utility Workers Union of America Local 464 (UWUA) with regard to the results of ISO New England's eighth Forward Capacity Auction (FCA 8). The order dismisses UWUA's amended protest as untimely for two reasons. First, in accordance with the notice of filing issued in this proceeding, protests were required to be filed on or before April 14, 2014. Second, at the time that UWUA filed the amended protest, this proceeding was no longer pending at the Commission, since, as confirmed by the U.S. Court of Appeals for the D.C. Circuit (Public Citizen, Inc. v. FERC, 839 F.3d 1165 (D.C. Cir. 2016)), the FCA 8 results had become effective by operation of law and the subsequent requests for rehearing had been dismissed.

FERC dismisses a petition for declaratory order

E-10, *Nevada Hydro Company, LLC*, Docket No. EL18-131-000. This order dismisses Nevada Hydro's petition for a declaratory ruling from the Commission that (1) its Lake Elsinore Advanced Pumped Storage (LEAPS) facility is a transmission facility consistent with Commission precedent; and (2) LEAPS is entitled to cost-based rate recovery under the California Independent System Operator Corporation's (CAISO) Transmission Access Charge (TAC). The order finds that the questions of whether LEAPS is a transmission facility and whether it is entitled to cost-based rate recovery through the TAC are premature at this time, explaining that the Commission can only determine whether or not LEAPS is a transmission facility after it has been studied through CAISO's Transmission Planning Process.

FERC approves an uncontested settlement agreement

E-11, *Pacific Gas and Electric Company*, Docket No. ER17-1750-002, *et al*. The order approves an uncontested settlement between PG& E and the City of Santa Clara doing business as Silicon Valley Power. The settlement resolves all issues related to an interconnection agreement between the parties.

FERC establishes hearing and settlement procedures

G-3, *Epsilon Trading, LLC, et al. v. Colonial Pipeline Company*, Docket Nos. OR18-7-000, OR18-12-000, OR18-17-000, and OR18-21-000. The order consolidates and establishes hearing and settlement procedures on the complaints against Colonial Pipeline challenging its rates, as well as its practices and charges related to transmix and product volume losses.

FERC denies petition for a declaratory order

H-1, *Utah Board of Water Resources and Washington County Water Conservancy District*, Docket No. EL18-56-000 and Project No. 12966-005. This order denies a petition for declaratory order filed by the Utah Board of Water Resources and Washington County Water Conservancy District, regarding hydroelectric generating facilities to be located on the proposed Lake Powell Pipeline Project, a large water delivery project that would convey water from Lake Powell in Arizona 140 miles to southwestern Utah for municipal and industrial use. Petitioners seek a determination that the Commission's licensing jurisdiction extends to the entire Hydro System as defined in the license application, including not only seven proposed hydroelectric developments to be located in and along the water delivery pipeline, but also some 89 miles of large diameter pipeline connecting those hydroelectric developments. The order also clarifies that the Commission would license only the hydroelectric generating facilities.

FERC denies rehearing

H-2, *Hydro-Kennebec LLC*, Project No. 2611-087. The order denies the request for rehearing filed jointly by Atlantic Salmon Federation, Maine Rivers, Natural Resources Council of Maine, and the Kennebec Chapter of Trout Unlimited (collectively, Intervenors) of Commission staff's March 14, 2018 order approving Hydro-Kennebec's request to extend the period of its Interim Species Protection Plan for the Hydro-Kennebec Project, located on the Kennebec River in Maine. On rehearing, Intervenors argued that Commission staff erred by refusing to reject National Marine Fisheries Service's May 26, 2017 Biological Opinion and refusing to reinitiate Endangered Species Act consultation with Intervenors included, and by failing to establish procedures for the resolution of a dispute under the Kennebec Agreement. The order denies rehearing of

both issues. The order strongly encourages the licensees involved with the Kennebec Agreement, including Hydro-Kennebec LLC, to continue to engage the other parties to the agreement, to discuss proposed measures, and to attempt to reach consensus.

FERC responds to motion to show cause

C-1, *Northern Natural Gas Company*, Docket No. CP09-465-002. This order responds to the Kansas Corporation Commission's (KCC) request for the Commission to require Northern Natural Gas Company (Northern) to secure all open production wells with access to the Cunningham storage formation. The KCC filed its motion after an accident damaged a production well that resulted in an uncontrolled release of Northern's storage gas. The order finds that Northern must protect the integrity of its storage field, ensuring that all wells with access to the storage field do not pose a risk to the integrity of the storage field. The order requires Northern to obtain the rights necessary to secure all open wells with access to the storage field.

FERC grants conditional authorization for an interstate natural gas storage facility

C-2, *Southern Star Central Gas Pipeline, Inc.*, Docket No. CP17-219-000. This order grants Southern Star conditional authority to expand the certificated boundary of the Webb Storage Field, located in Grant County, Oklahoma. Specifically, Southern Star is authorized to expand the certificated boundary of the Webb Storage Field: (1) horizontally in the North Nardin Area to include 320 acres of the proposed 480 acres in S1 T27N R3W in Grant County, Oklahoma, and 160 acres of the proposed 640 acres in S12 T27N R3W in Grant County, Oklahoma; and (2) vertically in the KLO Area to include the Owego Limestone and Wilcox Sandstone, as conditioned in the order.

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.

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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

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[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.

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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

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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.

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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

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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.

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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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Lesson Learned

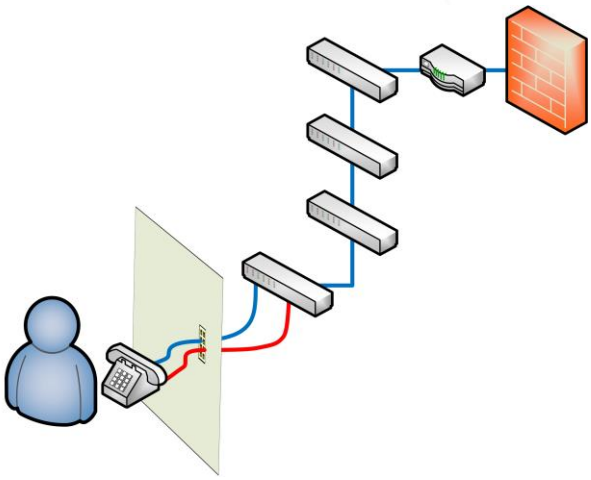
Networking Packet Broadcast Storms

Primary Interest Groups
Balancing Authorities (BAs)
Generator Operators (GOPs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs) that own and operate an Energy Management System (EMS)

Problem Statement
When a second network cable was connected from a voice over internet protocol (VOIP) phone to a network switch lacking proper settings, a packet broadcast storm prevented network communications from functioning, and supervisory control and data acquisition (SCADA) was lost for several hours. Broadcast storm events have also arisen from substation local area network (LAN) issues.

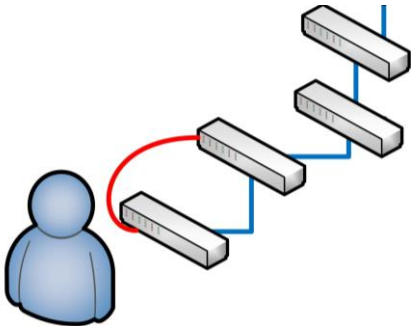
Details
A conference room was set up for a training class that needed to accommodate multiple PCs. The bridge protocol data unit (BPDU) packet propagation prevention setting was disabled on a port in the conference room in order to place a network switch off of that port. Upon completion of the training, the network switch was removed; however, the BPDU packet propagation setting was inadvertently not restored. As part of a telephone upgrade project, the traditional phone in this conference room was recently replaced by a VOIP phone. Later, an additional network cable was connected to the output port of this VOIP phone into a secondary network jack within the conference room.

When the second network cable was connected from a VOIP phone to a network switch lacking proper settings, a switching loop resulted. Spanning tree protocol is normally used to prevent switching loops from propagating broadcast packets continuously until the network capacity is overwhelmed. A broadcast packet storm from the switching loop prevented network communications from functioning and SCADA was lost for several hours. The effects of this condition are like a self-inflicted denial of service (DoS) attack.

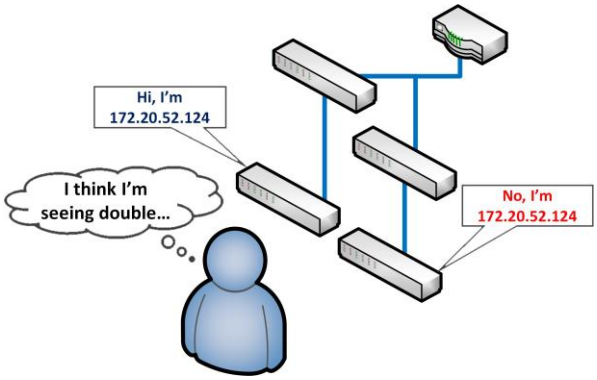


Similar broadcast storm events have occurred

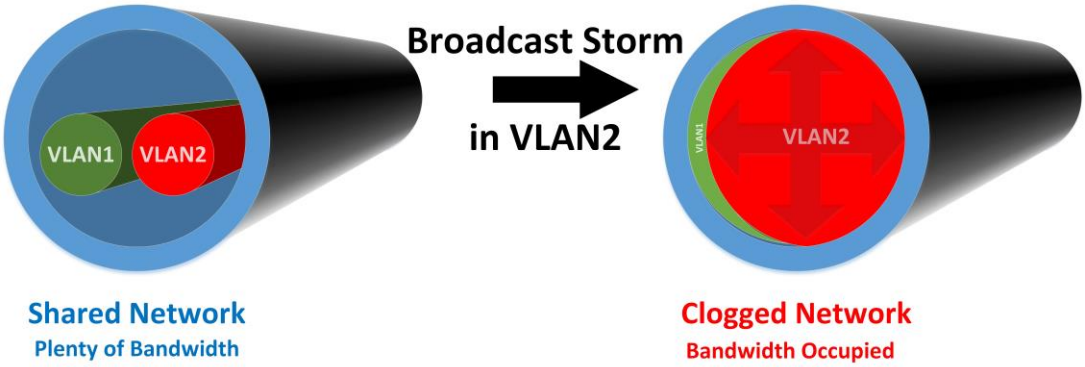
In one case, a substation technician performing routine system maintenance at a substation inadvertently connected an unused ethernet cable between two ethernet switches where an ethernet connection was already established. This created a communications loop with multiple ports seeing a duplicate MAC address. This loop created a broadcast storm that ultimately caused a loss of SCADA capability from the remote terminal units (RTUs) to the utility's EMS. Eventually, the cable was identified as the problem and removed, and EMS capability was fully restored.



At another location, a technician copied the configuration from another switch while preparing a new network switch to ensure their configuration was similar. However, the technician neglected to change the IP address of the new switch, so the new switch duplicated the IP address of the existing network switch. The duplicate IP address caused a packet storm that blocked network traffic and the entity's primary control center experienced a complete loss of SCADA data.



Another case involved substation data and commercial data on separate virtual local area networks (VLANs) passing through the same physical network switches. When station data was defeated by a broadcast storm due to an issue at a station under construction, the switches became overwhelmed, and the separate business traffic ceased as well.



Corrective Actions

In the IP phone case, the entity worked to narrow down the switching loop network location by isolating network segments, pinpointing the trouble spot, and finally shutting down the device and the port it was utilizing. They worked with the network hardware vendor to help review hardware global settings and receive remediation recommendations based on this specific incident.

The vendor recommended that network port settings be set to block BPDU packet propagation from non-spanning tree protocol enabled devices unless purposely allowed.[1]

In the station cases, locating and eliminating the unintended loop was the corrective action. In some cases, incompatibilities between network device manufacturers complicates use of spanning tree protocol.

In the cloned IP case, the solution was removing one of the two switches and assigning it a different IP address.

Lessons Learned

- Entities should use BPDU packet propagation prevention where a non-spanning tree protocol enabled device could be connected. These devices are usually end-user devices. Spanning tree protocol is normally used to prevent switching loops from propagating broadcast packets continuously until the network capacity is overwhelmed.
- Complete physical separation between SCADA Operations networks and business networks, VoIP, and external facing networks is preferred over VLAN for avoiding network traffic congestion and security issues. Where a vendor provides network services, a contract specifying maintenance of physical separation is necessary to enforce it.
- Where physical separation is not feasible, and Layer 2 Quality of Service (QoS) settings are supported, Layer 2 QoS can be used to avoid issues of heavy network traffic cutting off vital traffic. With proper QoS enabled for Layer 2 control packets, control packet rates exceeding a certain level to a switch will be dropped and not forwarded.[2]

- In addition to physical separation of networks and Layer 2 Quality of Service settings, there are additional, proprietary settings provided for additional control of central processing unit (CPU) loading and broadcast storm control. Entities should investigate these proprietary settings as appropriate with their networking vendor(s).
- Use a checklist and peer reviews when configuring and installing new equipment to avoid unintended loops or duplicate IP addresses.
- Establish standardized settings for network devices that include settings necessary to avoid packet storms.

[1] See https://learningnetwork.cisco.com/blogs/vip-perspectives/2016/03/10/advanced-stp-features-portfast-bpdu-guard-and-bpdu-filter and https://www.juniper.net/documentation/en_US/junos/topics/example/rate-limiting-storm-control-configuring.html for more technical discussions.

[2] A technical QoS setting discussion may be found here: https://www.cisco.com/c/en/us/td/docs/switches/lan/catalyst4500/12-2/44sg/configuration/guide/Wrapper-44SG/qos.pdf

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For more Information please contact:

NERC – Lessons Learned (via email)	MRO – Event Analysis
Source of Lesson Learned:	Midwest Reliability Organization
Lesson Learned #:	20181001
Date Published:	October 2, 2018
Category:	Communications

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